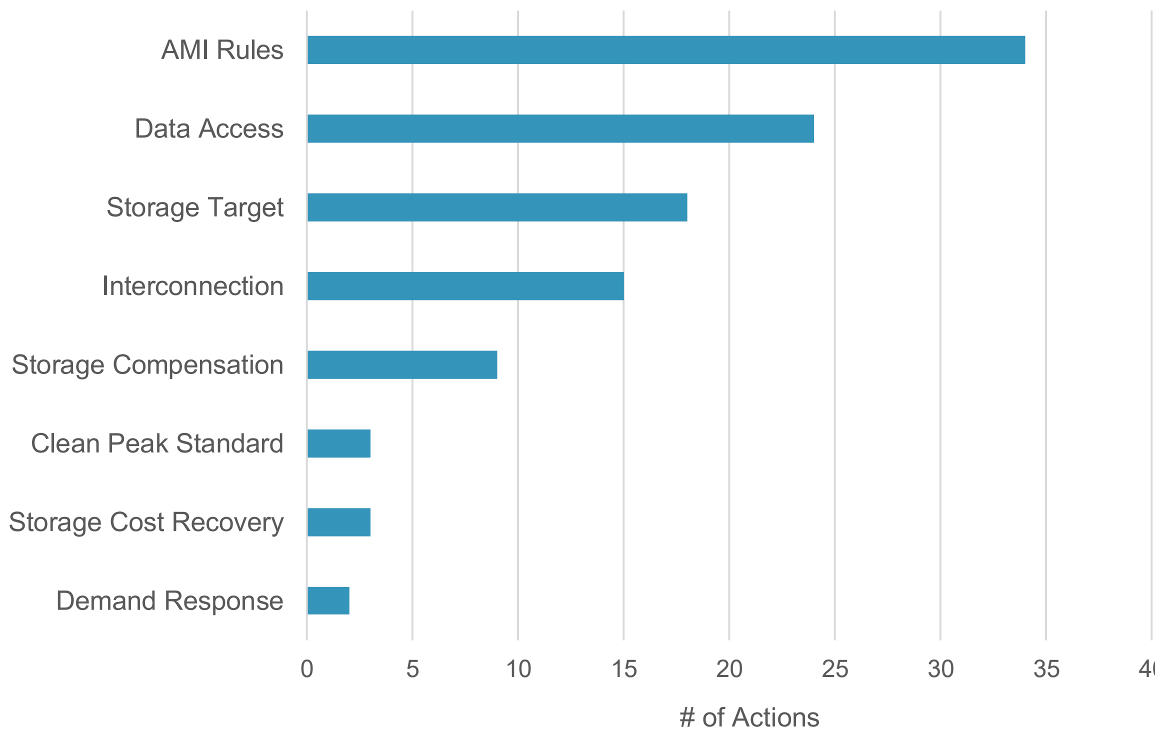
Massachusetts also adopted the nation's first "clean peak standard" in 2018, requiring a certain amount of system peak demand to be supplied with clean energy resources, including demand response and energy storage charged by renewable resources. An Arizona Corporation Commissioner proposed a clean peak target in 2018 as part of a broader Energy Modernization Plan, which is currently under consideration.

Several states also considered interconnection rules and compensation frameworks for energy storage systems in 2018. Minnesota and Nevada regulators adopted revised interconnection rules with specific requirements for energy storage systems, and the Arizona Corporation Commission Staff published proposed interconnection rules including energy storage provisions. Arizona does not currently have statewide interconnection standards.

Figure 16. Most Common Types of Policy Actions in 2018



Note: Policy types with only one action taken in 2018 are excluded from this graph.

The New York Public Service Commission approved its "Hybrid Tariff" for generation resources eligible for compensation under the Value of Distributed Energy Resources tariff that are paired with energy storage facilities ("hybrid facilities"). The tariff includes four options, based on the system usage, and provides compensation for environmental benefits depending on whether the energy injected into the grid is from a renewable resource or not. Regulators in California, Colorado, and Massachusetts also considered requirements for solar-plus-storage net metering.

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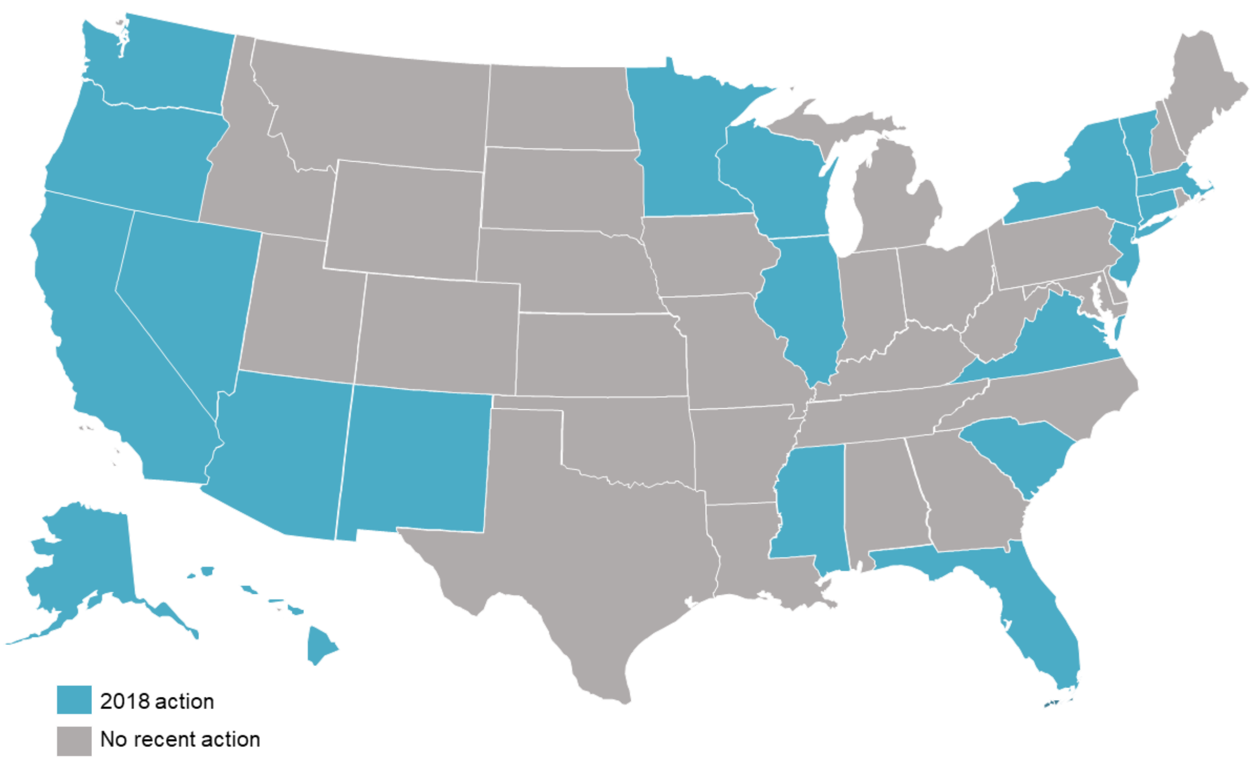
FINANCIAL INCENTIVES REVIEW

Key Takeaways:

- In 2018, there were 46 actions ongoing or under consideration in 20 states related to incentives for grid modernization technologies.
- Of these, 37 were proposals for energy storage incentives, 5 were for microgrid incentives, 2 provided incentives for distributed generation paired with smart inverters, 2 provided demand response incentives, and one incentive was for grid modernization broadly.
- Eight states – Alaska, California, Illinois, Massachusetts, Minnesota, Nevada, New York, and Wisconsin – approved some kind of grid modernization incentives during 2018.

In 2018, there were 46 actions ongoing or under consideration in 20 states related to incentives for grid modernization. These actions include tax credits, property and sales tax exemptions, grant programs, rebate programs, loan programs, and property assessed clean energy (PACE) financing programs. In 2018, rebate programs were by far the most common type of incentive under consideration.

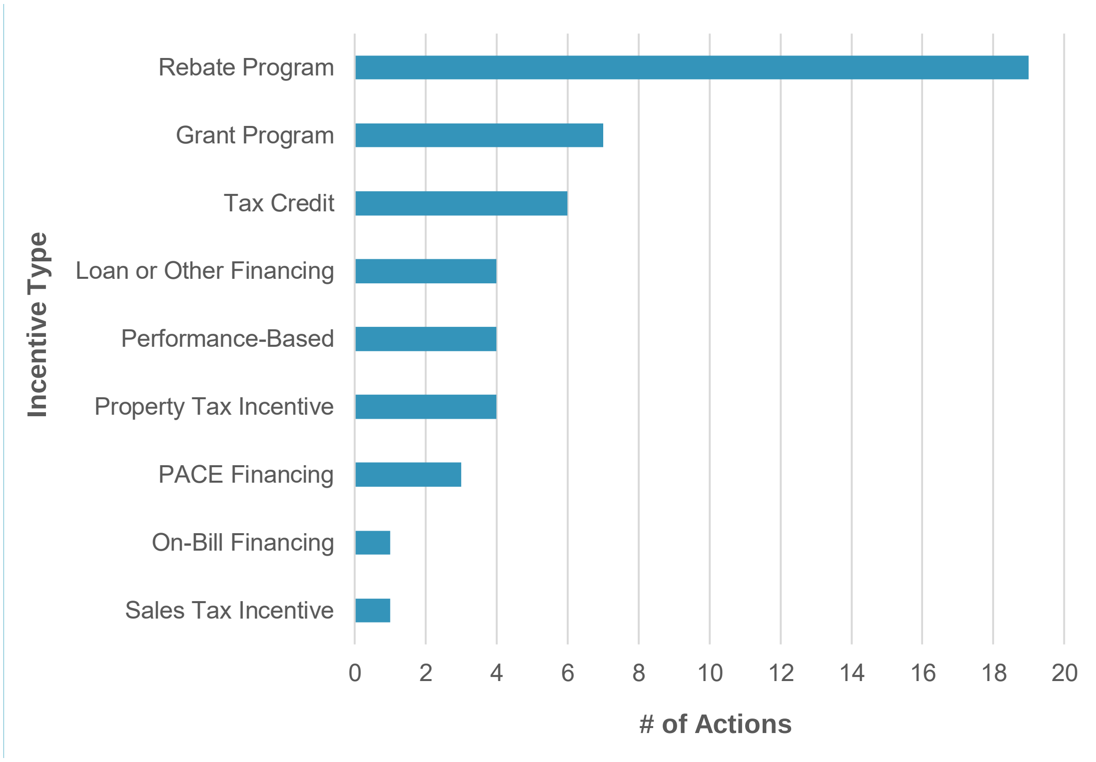
Figure 17. 2018 Action on Financial Incentives



Legislatures in three states – Alaska, Minnesota, and New York – enacted bills creating incentives for grid modernization technologies. In Minnesota, a bill expanded the eligibility for an existing loan program, respectively, to include energy storage. Alaska passed a bill creating an on-bill financing mechanism for energy storage and other technologies, and New York passed a bill creating a property tax abatement for energy storage technology.

Regulatory commissions in six states also approved incentives in 2018. California regulators approved incentive programs proposed by San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE) for energy storage for low-income customers. SDG&E's incentive is for $1.20 per Watt-hour, and SCE's incentive is for $0.75 per Watt-hour. Nevada regulators approved regulations for NV Energy's energy storage rebate program, as required by 2017 legislation. NV Energy's small energy storage incentive is $0.22 per Watt-hour for residential customers on a time-of use rate and $0.11 per Watt-hour for customers not on a time-of-use rate.

Figure 18. 2018 Action on Incentives, by Incentive Type



The Massachusetts Department of Public Utilities approved a tariff with an adder for energy storage as part of the state's SMART incentive program for solar generation, and New York introduced an additional incentive for solar installations paired with storage as part of its NY-SUN program. Illinois regulators also approved two utility programs providing rebates for distributed generation systems using smart inverters, and the Wisconsin Public Service Commission ordered that energy storage is eligible for an existing state grant program.

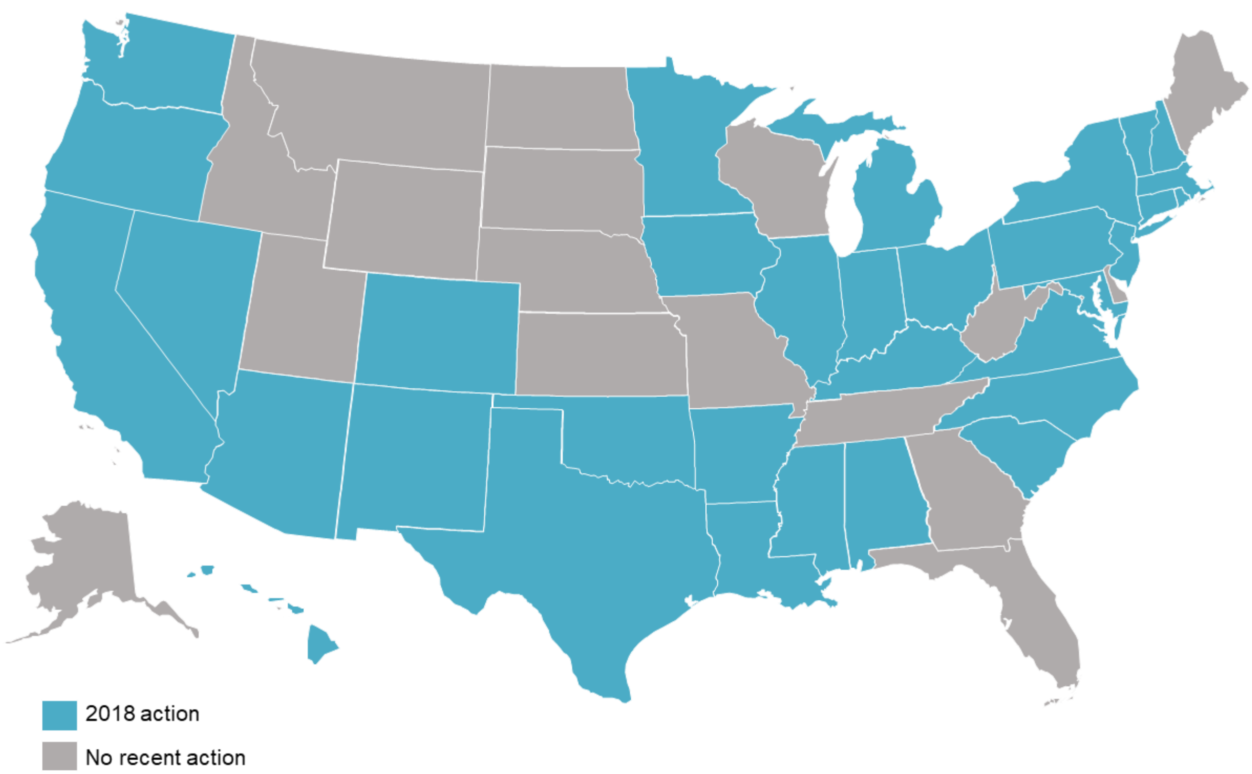
STATE & UTILITY DEPLOYMENT REVIEW

Key Takeaways:

- In 2018, there were 81 pending or decided proposals from state legislators or utilities across 33 states to deploy grid modernizing technologies, such as advanced metering infrastructure (AMI), smart grid components, microgrids, and energy storage.
- Proposals to deploy energy storage facilities were the most common type of request for the second year in a row, with 44 actions across 25 states.
- Twelve investment proposals were fully approved (all either AMI, demand response, or energy storage project proposals), 10 were partially approved, and 7 were rejected in 2018.

Deployment of energy storage facilities was the most widespread type of grid modernization action for the second year in a row, with 25 states considering legislation or utility requests to develop new storage projects. Meanwhile, AMI deployment activity declined in 2018, largely due to many utilities having already fully deployed AMI throughout their service territories. A total of 33 states considered 81 legislative or regulatory proposals to deploy grid modernizing technologies during 2018.

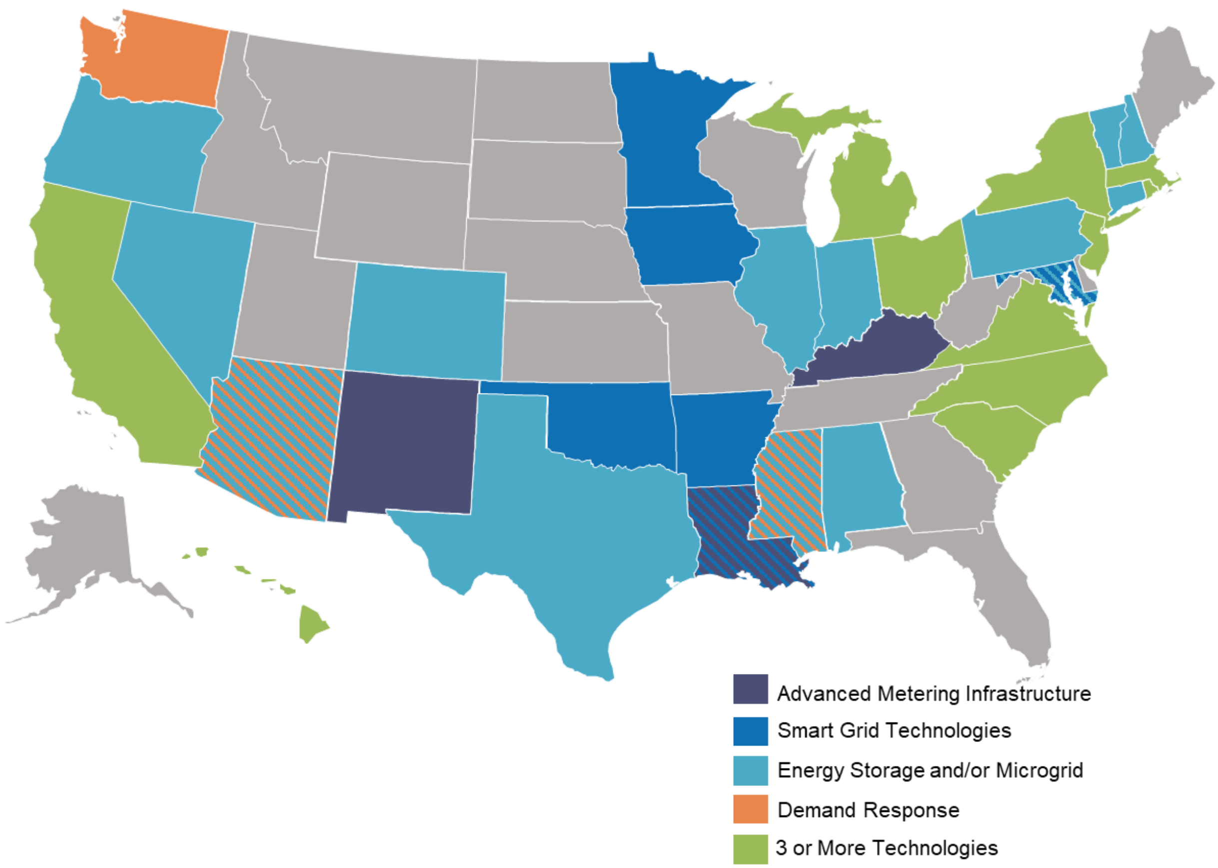
Figure 19. 2018 Action on Grid Modernization Technology Deployment



Advanced Metering Infrastructure

In 2018, a total of 13 states had 24 active proceedings related to AMI deployment, with utilities in 8 utilities filing new deployment requests during the year. In several cases, regulators denied utility requests to deploy AMI in 2018, finding that the benefits, as presented by the utility, do not justify the costs at this time. Regulators in Kentucky, Massachusetts, and New Mexico rejected AMI deployment requests during 2018, and Virginia regulators denied Dominion's request in early 2019. Regulators approved AMI deployment proposals in Hawaii, Kentucky, Louisiana, New York, and North Carolina.

Figure 20. 2018 Proposed Deployments by Technology Type



Smart Grid / Distribution System Modernization

In 2018, 17 states had active proceedings regarding the deployment of technologies aimed at modernizing the distribution system. In several states, including Massachusetts, Minnesota, North Carolina, and Rhode Island, regulatory bodies rejected or drastically scaled back major smart grid investment proposals, often approving parts of the requests and asking utilities to later present revised plans for the rejected elements. New smart grid investment proposals were filed in Arkansas, Iowa, Louisiana, Maryland, Massachusetts, New Jersey, Ohio, Oklahoma, South Carolina, and Virginia in 2018.

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Table 6. Proposed AMI and Smart Grid Investment Cost Figures

State	Utility	Proposed Budget	Approved Budget
Arkansas	Oklahoma Gas & Electric	$20 Million	Pending
California	Southern California Edison	$2.1 Billion	Pending
Hawaii	HECO, HELCO, MECO	$86.3 Million	Pending
Iowa	Alliant Energy	$66 Million	N/A
Kentucky	Duke Energy Kentucky	$23.4 Million	$23.4 Million
Kentucky	Kentucky Utilities, Louisville Gas & Electric	$250.4 Million	$0
Louisiana	Entergy New Orleans	$75 Million	$75 Million
Louisiana	Entergy New Orleans	$59.3 Million	Pending
Maryland	Potomac Edison	$10.7 Million	Pending
Massachusetts	Eversource	$400 Million	$133 Million
Massachusetts	National Grid	$792.4 Million	$82 Million
Massachusetts	Unitil	$24 Million	$4.4 Million
Michigan	Consumers Energy	$339 Million	N/A
Michigan	DTE Electric	$375 Million	N/A
Michigan	Upper Peninsula Power Company	$15.6 Million	Pending
Minnesota	Xcel Energy	$140 Million	$0
New Jersey	Atlantic City Electric	$338.2 Million	Pending
New Jersey	Jersey Central Power & Light	$386.8 Million	Pending
New Jersey	PSE&G New Jersey	$810.3 Million	Pending
New Mexico	Public Service Company of New Mexico	$87.2 Million	$0
New York	National Grid	$446.35 Million	Pending
New York	New York States Electric & Gas, Rochester Gas & Electric	$513,221	Pending
New York	PSEG Long Island	$204 Million	N/A
North Carolina	Duke Energy Carolinas	$2.4 Billion	$90.9 Million
Ohio	Dayton Power & Light	$866.9 Million	Pending
Ohio	First Energy	$450 Million	Pending
Ohio	First Energy	$600 Million	$600 Million (Appealed)
Oklahoma	Public Service Company of Oklahoma	$175 Million	Pending
Rhode Island	National Grid	$102 Million	$21.3 Million
South Carolina	Duke Energy Carolinas, Duke Energy Progress	$455 Million	Pending
Virginia	Appalachian Power Company	$587.4 Million	Pending
Virginia	Dominion Energy	$1.49 Billion	$154.5 Million (Jan. 2019)
TOTAL		$14.18 Billion	$1.93 Billion

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Many of the utilities proposing smart grid investments are also requesting special ratemaking treatment for these investments, namely cost recovery through riders. Kentucky and North Carolina regulators rejected Duke Energy's request for grid riders in both states, while requests for new riders are pending in Louisiana, Maryland, and New Jersey. The Massachusetts Department of Public Utilities approved the use of a targeted cost recovery mechanism for recovery of the investor-owned utilities' grid modernization capital and O&M costs. Delaware lawmakers also authorized a new Distribution Service Improvement Charge to recover the costs of certain distribution system improvements.

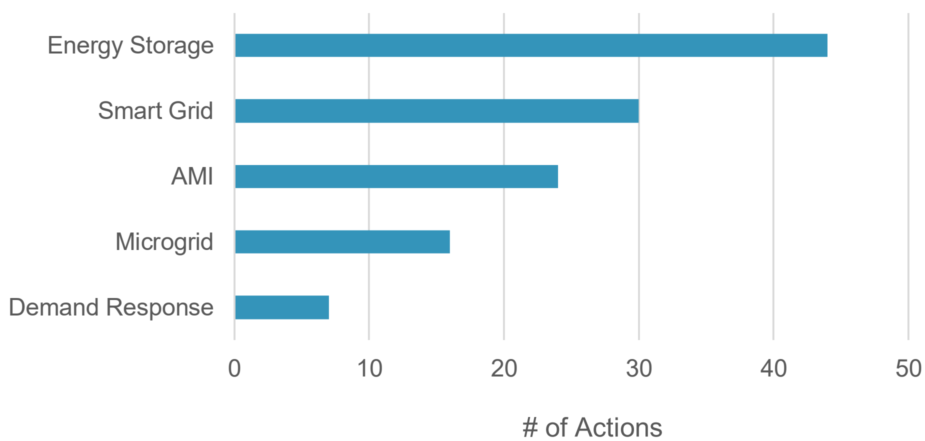
Table 7. Proposed Utility Energy Storage Projects

State	Utility	Proposed Size	Approval
Arizona	Arizona Public Service	106 MW	N/A
California	Liberty Utilities	2.6 MW	Pending
California	Pacific Gas & Electric	166 MW	Approved
California	Pacific Gas & Electric, Southern California Edison	175 MW	Approved
California	San Diego Gas & Electric	83.5 MW	Approved
California	San Diego Gas & Electric	166 MW	Approved
California	Southern California Edison	40 MW	Approved
California	Southern California Edison	70 MW	Approved
Connecticut	United Illuminating Company	1.25 MW / 2.5 MWh	Stayed
Hawaii	HECO, HELCO, MECO	20 MW	Pending
Hawaii	HECO, HELCO, MECO	100 MW	Pending
Illinois	Commonwealth Edison	500 kW (microgrid)	Approved
Indiana	Duke Energy Indiana	5 MW / 5 MWh (microgrid)	Approved
Maryland	Pepco	1.6 MW (microgrid)	Not Approved
Massachusetts	National Grid	14 MW	Pending
Michigan	Consumers Energy	1.25 – 1.75 MW	N/A
Michigan	DTE Electric	2 MW	N/A
New Hampshire	Liberty Utilities	5 MW (total, at 1,000 residences)	2.5 MW (500 residences) Approved
North Carolina	Duke Energy Carolinas	300 MW	Not Approved
North Carolina	Duke Energy Progress	4 MW (microgrid)	Pending
Ohio	Duke Energy Ohio	10 MW	Approved
Oregon	Pacificorp	4 MW / 11 MWh	2.8 MW / 7 MWh Approved
Oregon	Portland General Electric	88.5 MW – 104.5 MW	23 MW Approved
Pennsylvania	Duquesne Light Company	(microgrid)	Not Approved
Rhode Island	National Grid	2 MWh	750 kW Approved
Texas	AEP Texas North Company	1.5 MW / 3 MWh	Not Approved
Vermont	Green Mountain Power	1 MW / 4 MWh	Approved
Vermont	Green Mountain Power	2 MW / 8 MWh (microgrid)	Pending
Vermont	Green Mountain Power	2 MW / 8 MWh (microgrid)	Pending

Energy Storage

In 2018, 25 states had active proceedings or legislation related to energy storage deployment. Several of these projects were proposed as pilots, as part of microgrids, or as non-wires alternatives. The greatest amount of energy storage capacity – over 700 MW – was approved in California, largely driven by the state's energy storage procurement target. Projects were also approved in Illinois, Indiana, New Hampshire, Ohio, Oregon, Rhode Island and Vermont. Liberty Utilities' approved project in New Hampshire involves the utility owning behind-the-meter battery storage systems on residential properties. Utilities in other states have also announced planned storage investments as part of integrated resource plans or issued RFPs for storage capacity. Table 7 provides a summary of proposed energy storage projects under consideration during 2018.

Figure 21. 2018 Proposed Deployments by Technology Type



Microgrids

Ten states had 16 active proceedings or pending bills related to microgrid deployment in 2018. Hawaii lawmakers enacted one bill during 2018, which authorizes the National Energy Laboratory of Hawaii to build a microgrid demonstration project. Another bill directing the Public Utilities Commission to develop a microgrid services tariff was also enacted in Hawaii during the year. Regulators in Illinois and Indiana approved proposals from Commonwealth Edison and Duke Energy, respectively, to construct microgrids. Proposed projects were not approved in Maryland and Pennsylvania, and microgrid proposals remain under consideration in North Carolina and Vermont.

Demand Response

There were seven open proceedings in six states – Arizona, California, Michigan, Mississippi, New York, and Washington – related to demand response during 2018. California regulators approved a proposal from Southern California to procure 55 MW of demand response, and Puget Sound Energy in Washington issued an RFP for 351 MW of demand response.

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Q4 QUARTERLY REPORT

OVERVIEW OF Q4 2018 GRID MODERNIZATION ACTION

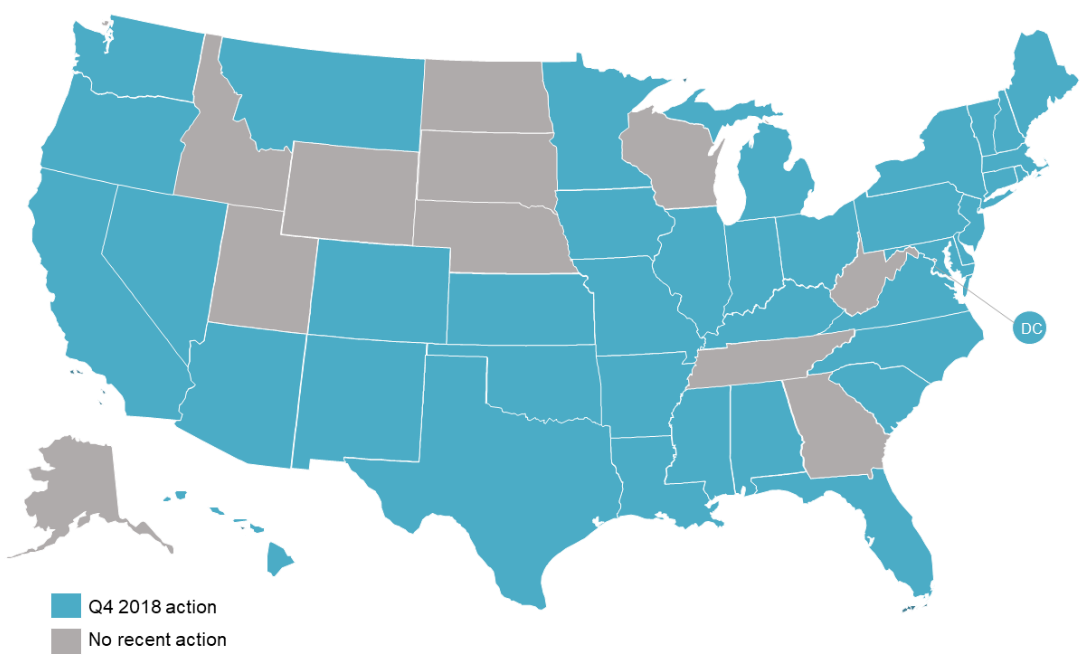
Table 8 provides a summary of state actions related to grid modernization occurring during Q4 2018. Of the 280 actions catalogued, the most common were those related to policies (58), deployment (52), and planning and market access (52). The actions occurred across 39 states plus DC in Q4 2018 (Figure 22). Box 3 highlights the states that saw the most grid modernization action during Q4 2018, described in greater detail in the following sections.

Table 8. Q4 2018 Summary of Grid Modernization Actions

Type of Action	# of Actions	% by Type	# of States
Policies	58	21%	21 + DC
Deployment	52	19%	25
Planning and Market Access	52	19%	20 + DC
Studies and Investigations	47	17%	27 + DC
Business Model and Rate Reform	43	15%	22
Financial Incentives	28	10%	12
Total	**280**	**100%**	**39 States + DC**

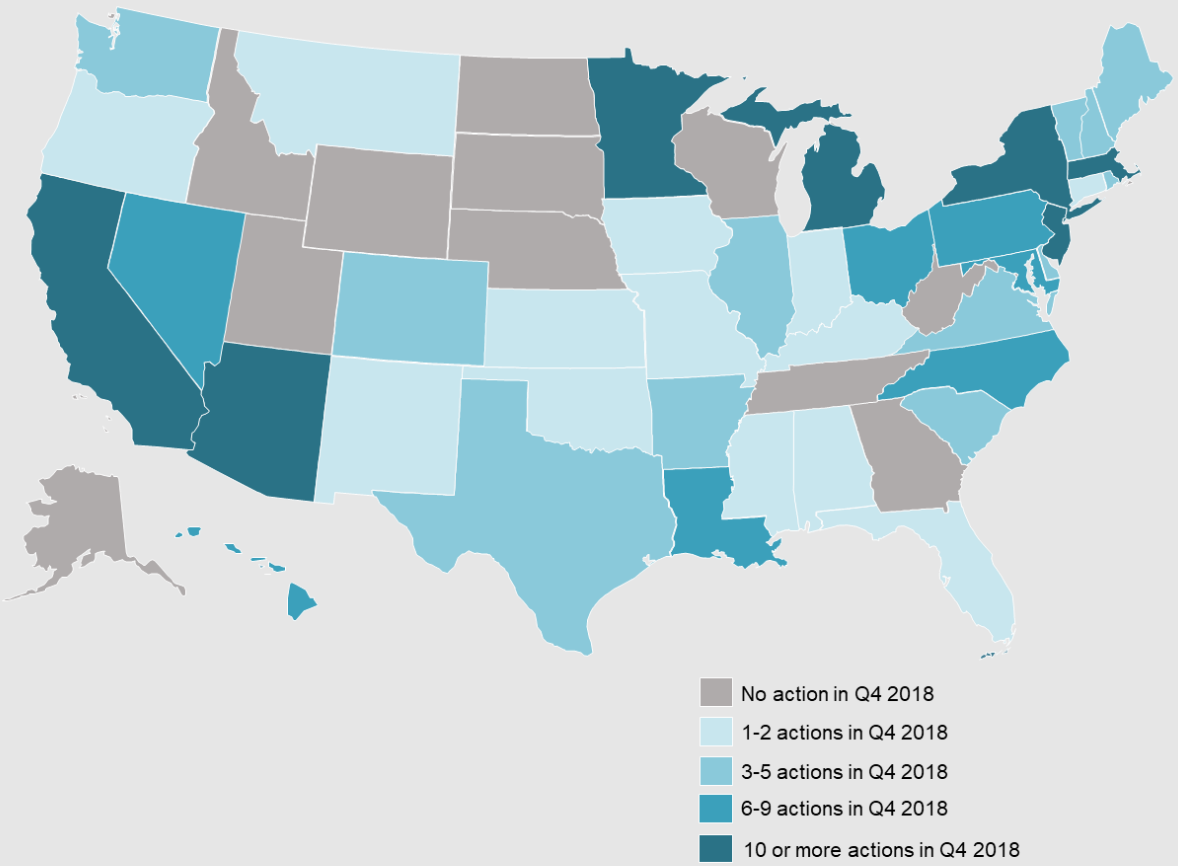
Note: The "# of States/ Districts" total is not the sum of the rows because some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 22. Q4 2018 Legislative and Regulatory Action on Grid Modernization



Grid modernization activity increased slightly in Q4 2018, even with most state legislatures out of session during the quarter. A total of 280 actions were taken in Q4 2018, with activity increasing in all categories except studies and investigations and policies. Compared to Q4 2017, action increased by 43% in Q4 2018. It is expected that grid modernization activity will increase substantially in Q1 2019 as lawmakers introduce new bills related to grid modernization and energy storage.

Figure 23. Q4 2018 Action on Grid Modernization, by Number of Actions



The states taking the greatest number of actions related to grid modernization in Q4 2018 are shown in Figure 25. New York, California, and New Jersey took the most action during the quarter, followed by Massachusetts, Michigan, Arizona, and Minnesota. A total of 39 states plus DC took action on grid modernization during Q4 2018. The greatest amounts of grid modernization activity were concentrated in the Mid-Atlantic, Southwest, and Upper Midwest during the quarter.

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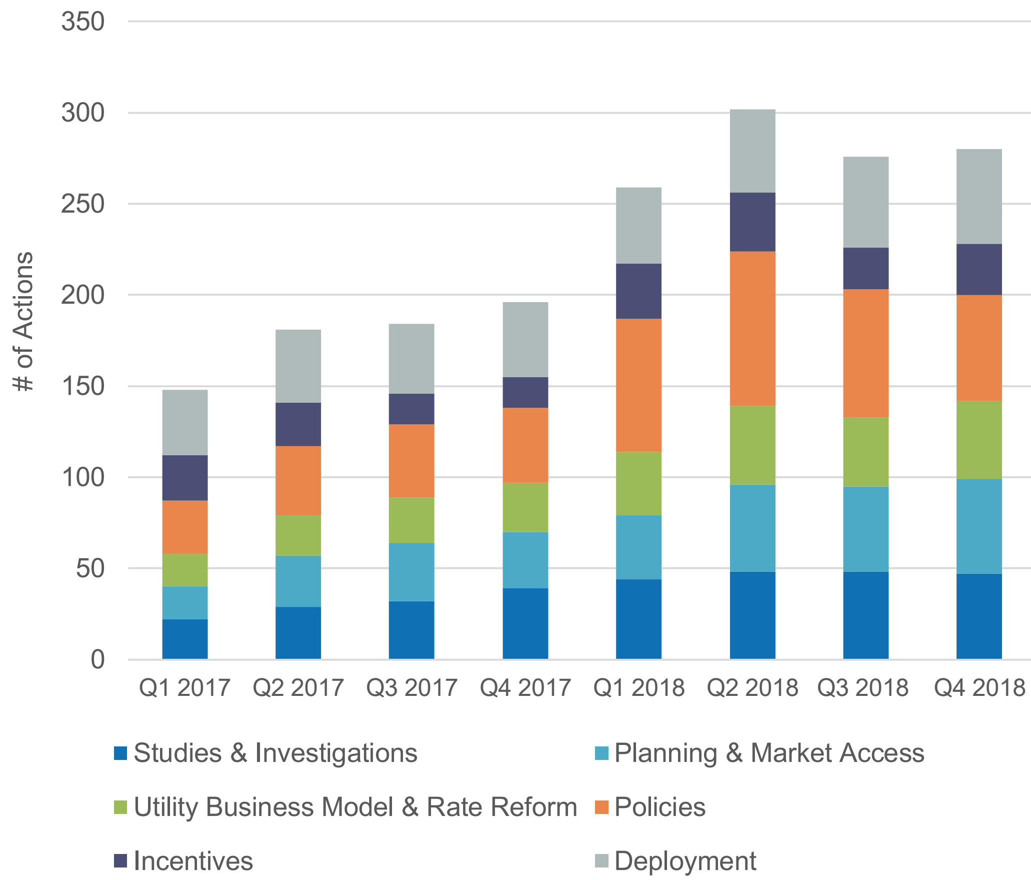
Figure 24. Total Number of Grid Modernization Actions by Quarter



Of the 280 actions taken in Q4 2018, 55 were legislative, while 225 were regulatory. As most states begin their legislative sessions in Q1 2019, this balance is likely to shift substantially next quarter. Although the majority of bills under consideration will not ultimately be enacted, these actions do indicate where policymakers are considering various aspects of grid modernization.

Figure 26 displays the most active states of Q4 2018 by the status of each action taken (for bills, I = introduced, P1/P2 = passed one or both chambers, E = enacted, D = dead). For the purposes of this graph, each individual action is assigned a status, so bills containing several different grid modernization components may be counted multiple times. The graph is not intended to be a precise representation, but rather to show that while some states can be considered very active, not all of the actions counted lead to policy changes or technology deployments.

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Figure 25. Most Active States of Q4 2018

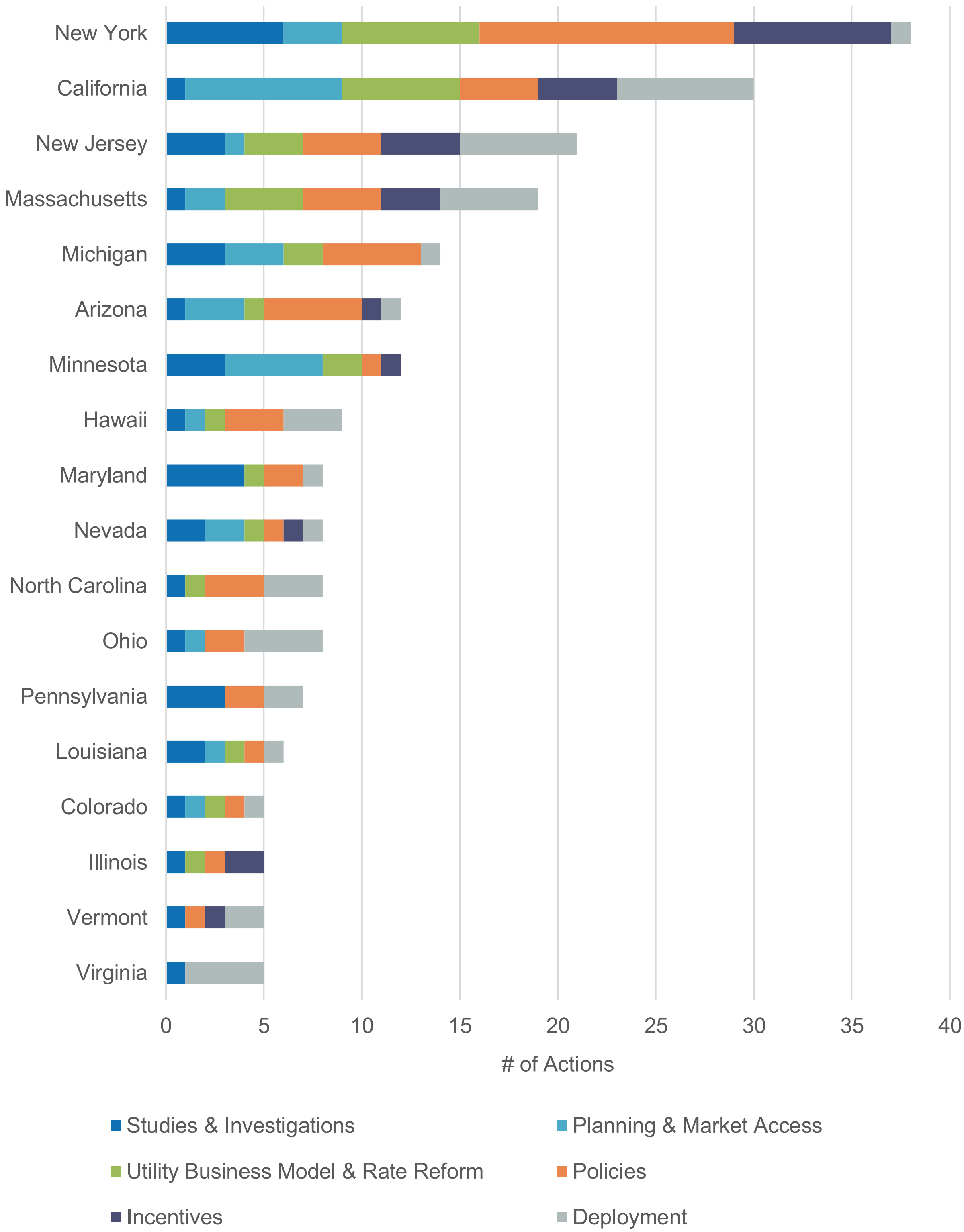

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Figure 26. Most Active States of Q4 2018, by Action Status

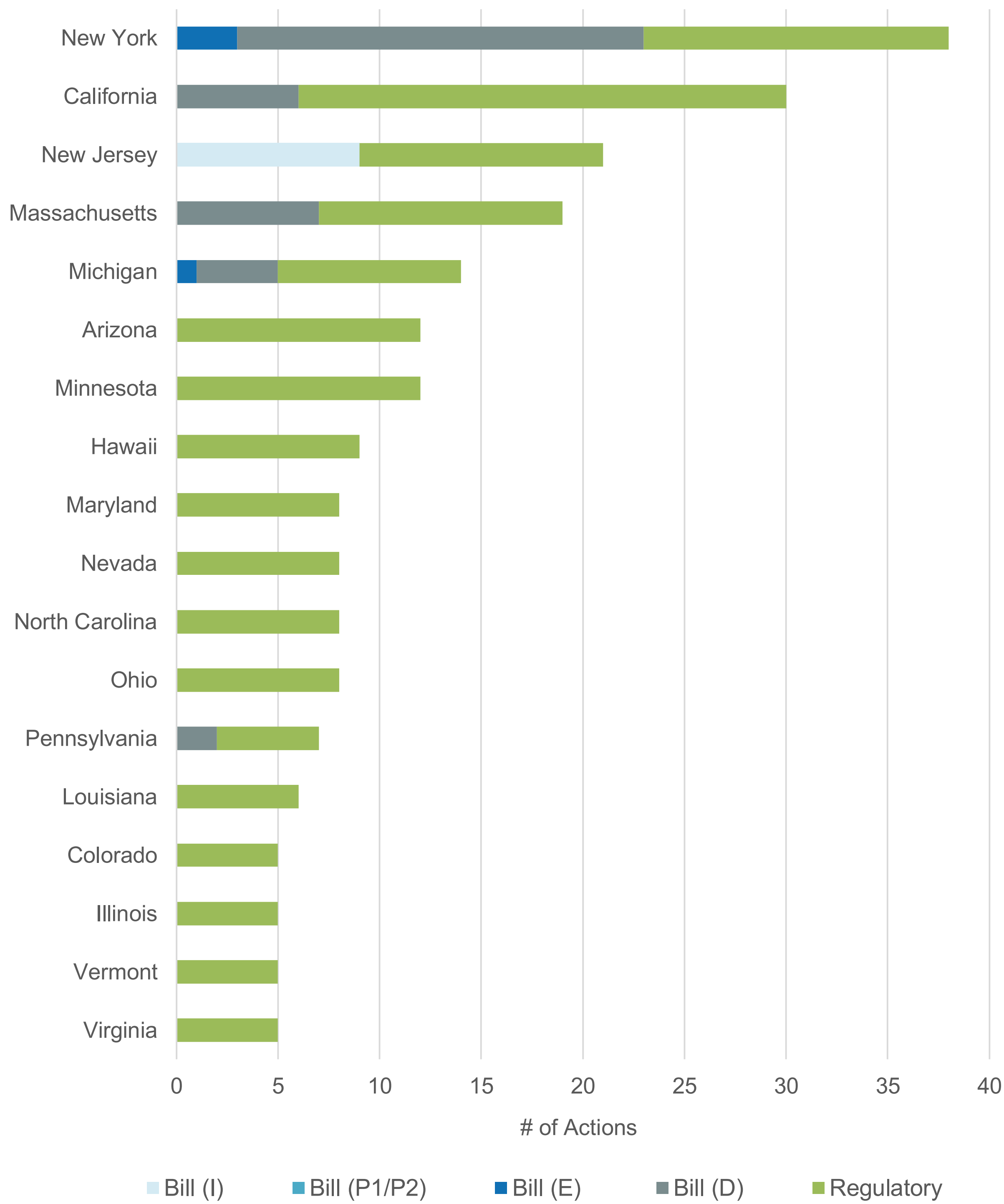

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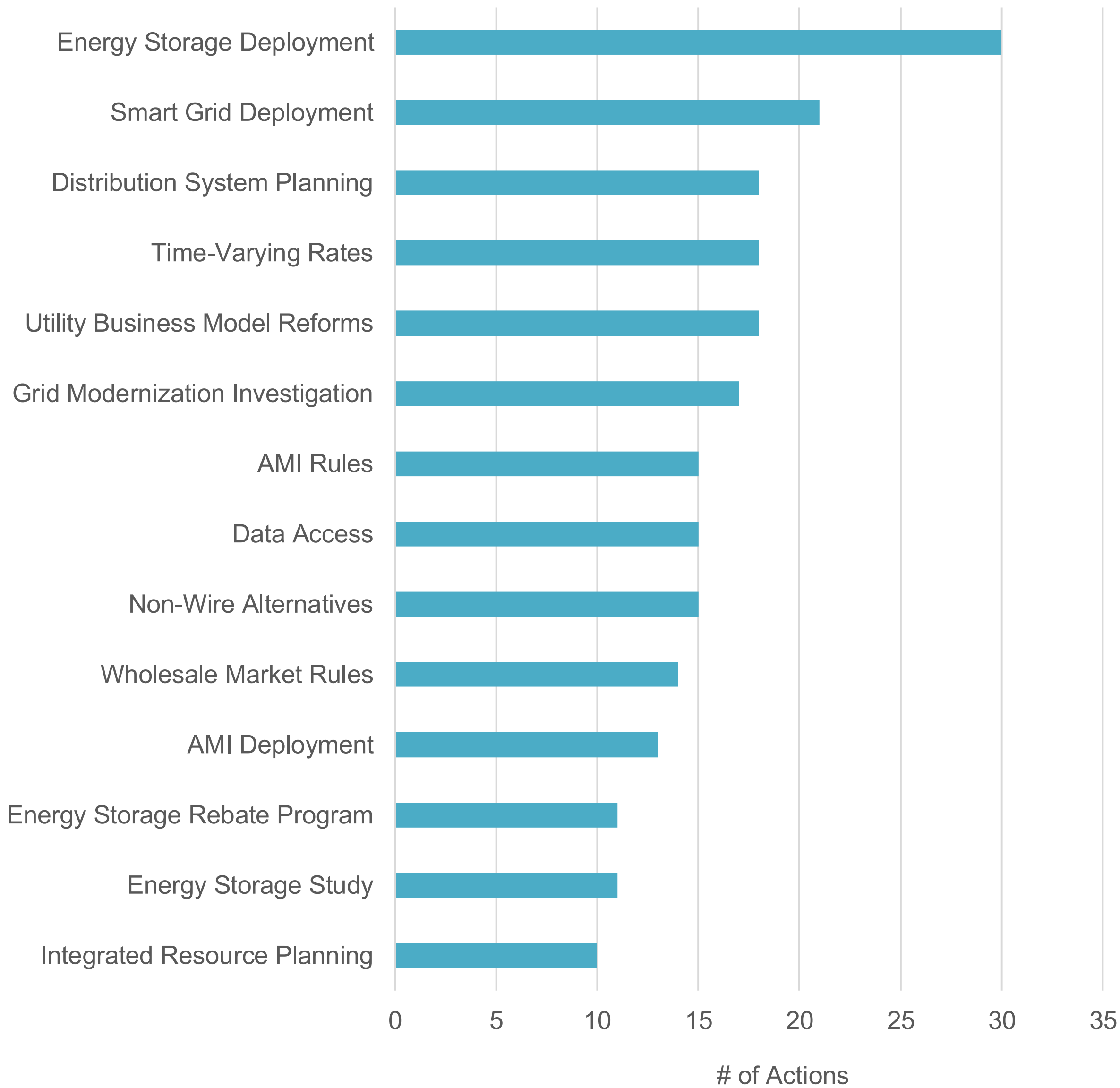
Figure 27. Most Common Types of Actions Taken in Q4 2018



The most common types of actions taken during Q4 2018 related to energy storage deployment (30), followed by smart grid deployment (21), distribution system planning (18), time-varying rates (18), utility business model reforms (18), and grid modernization investigations (17). States are increasingly moving beyond some of the foundational steps of grid modernization, such as investigations and AMI deployment, and toward actions like revising planning processes and the incentive structures influencing investment by both utilities and customers (i.e., utility business models and retail rate designs).

Of the 39 states taking grid modernization action in Q4 2018, at least 31 states took actions related to energy storage. Some of the most common types of energy storage actions were related to energy storage deployment, distributed energy resource and distribution system planning efforts, energy storage studies, non-wires alternatives, wholesale market participation

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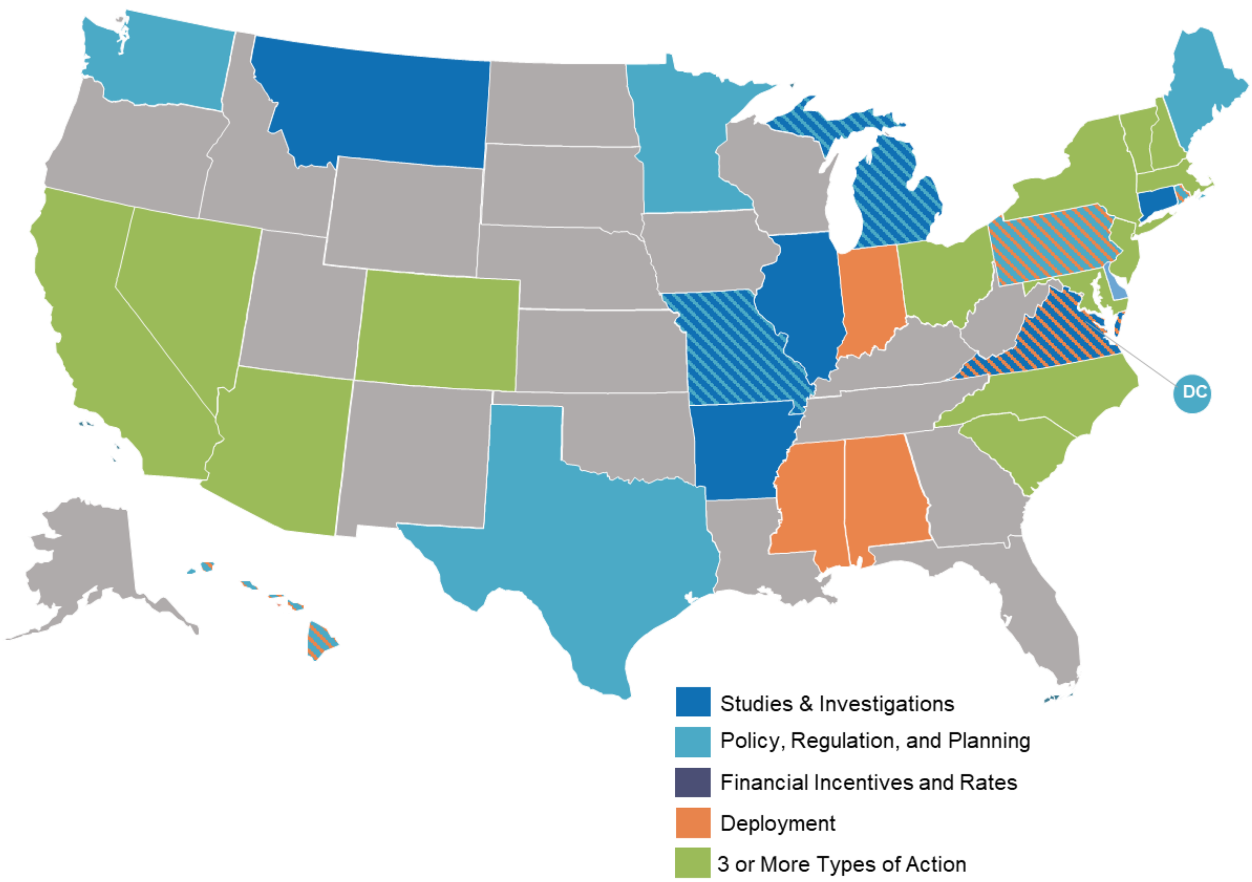
rules, financial incentives, and studies. Several states are also examining energy storage as part of grid modernization investigatory proceedings, considering energy storage procurement targets or clean peak standards, and reviewing energy storage compensation and interconnection rules.

Figure 28. Q4 2018 Action on Energy Storage, by Type of Action



Box 3. Top Five Grid Modernization Actions of Q4 2018

Energy Storage Studies Published in Maryland, Nevada, and North Carolina

Energy storage studies were published in Maryland, Nevada, and North Carolina during Q4 2018. Maryland's study focused on policy options for expanding storage development in the state, while North Carolina's study quantified the potential value of various storage applications and presented policy options to prepare for, facilitate, and accelerate storage deployment. Nevada's study determined that 700 to 1,000 MW of utility-scale battery could be deployed cost-effectively by 2030.

Duke Energy Requests Approval for Grid Improvement Plan in South Carolina

As part of general rate cases filed by Duke Energy Carolinas and Duke Energy Progress in South Carolina in November 2018, the utilities requested approval for their $455 million Grid Improvement Plan. The plan includes a variety of investments in smart grid technologies, as well as AMI and energy storage. The plan also includes development of a new integrated system operations planning process.

New York PSC Approves Energy Storage Goal and Roadmap

In December 2018, the New York Public Service Commission formally adopted an energy storage goal of 3,000 MW by 2030. The Commission also approved a roadmap to achieve this target. The roadmap includes competitive direct procurement, a system efficiency target, non-wires alternatives preparation, an incentive plan, a distributed energy resource data platform, and value stack tariff refinement.

Wholesale Market Operators File FERC Order 841 Compliance Plans

In December 2018, California ISO, ISO New England, Midcontinent ISO, New York ISO, PJM Interconnection, and the Southwest Power Pool filed plans to comply with Federal Energy Regulatory Commission (FERC) Order 841, issued in February 2018. FERC Order 841 requires wholesale market operators to establish rules allowing energy storage resources to participate in energy, capacity, and ancillary services markets.

Ohio Regulators Open Three New PowerForward Grid Modernization Dockets

Following the release of the PowerForward Roadmap, the Public Utilities Commission of Ohio opened three new dockets related to the PowerForward grid modernization initiative in October 2018. One docket is for the PowerForward Collaborative, a continued stakeholder engagement effort, while the other two dockets relate to distribution system planning and data access issues.

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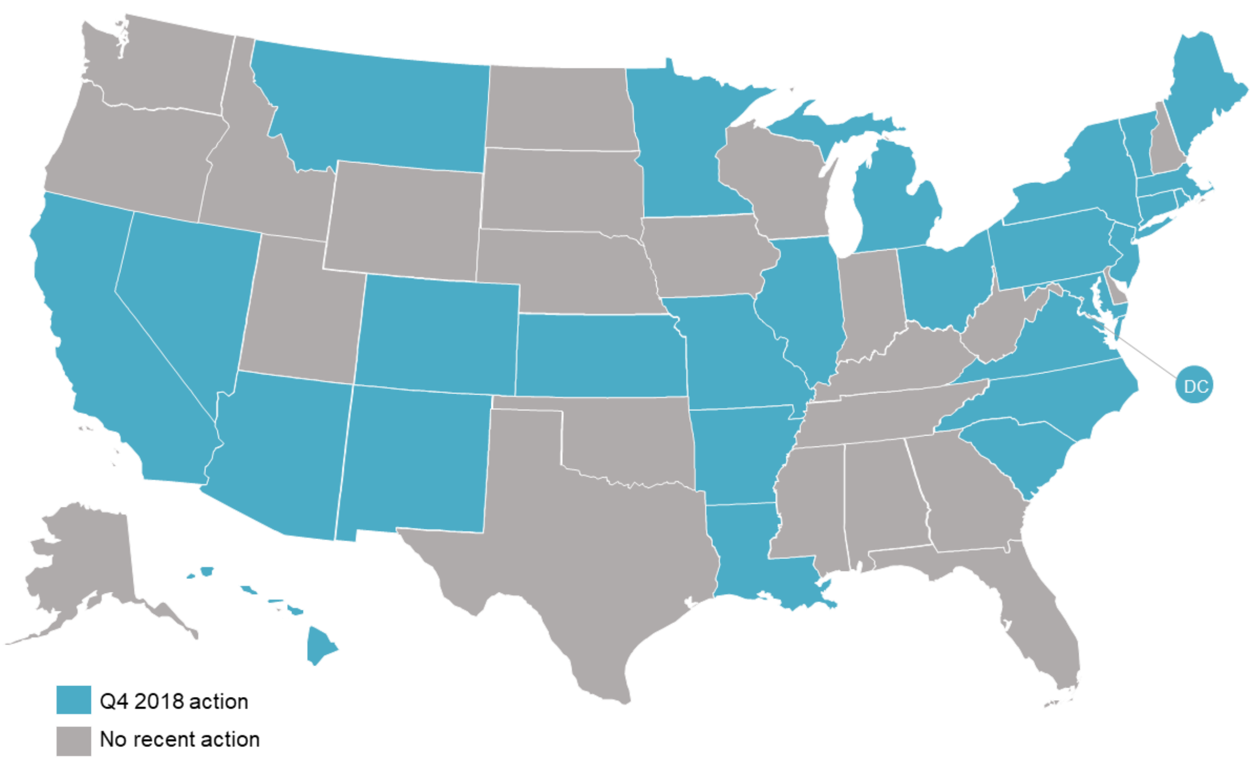
STUDIES AND INVESTIGATIONS

Key Takeaways:

- In Q4 2018, 27 states plus DC took action to study or investigate issues related to grid modernization, energy storage, utility business models, and rate reform.
- Three states – Maryland, Nevada, and North Carolina – completed energy storage studies during Q4 2018.
- Colorado, Connecticut, and Illinois concluded broad grid modernization investigatory efforts in Q4 2018, with a draft final report released in Illinois.

Several of the states addressing grid modernization are citing a need for greater information to inform the legislative and regulatory processes. Many states do not yet have significant experience with grid modernizing technologies, and in some cases, these technological advancements are prompting an examination of the state's overall vision for the electric grid and an analysis of potential policy mechanisms to achieve that vision. States are informing the policy process by commissioning studies and investigations into both the technologies and regulatory practices and structures tied to their deployment.

Figure 29. Action on Grid Modernization Studies and Investigations (Q4 2018)



Three energy storage studies, all initiated by state legislation enacted in 2017, were completed in Maryland, Nevada, and North Carolina in Q4 2018. Maryland's study is policy-focused, describing many different policy options available to increase energy storage deployment. The study identifies three policy options most relevant to the state: (1) removing barriers by updating rate designs and regulations, (2) supporting storage through targets and/or incentives, and (3) taking a more active role in overseeing distribution system planning. The studies conducted in Nevada and North Carolina feature more quantitative analysis. Nevada's study found that 700 to 1,000 MW of utility-scale battery storage could be deployed cost-effectively by 2030, and North Carolina's study quantifies the potential value of different energy storage applications, with most of these becoming cost-effective by 2030.

Table 9. Upcoming Grid Modernization Study Deadlines

State	Topic	Expected Completion
Hawaii	Utility Business Models	January 2019
New Jersey	Energy Storage	May 2019
Michigan	Demand Response	May 2019
New Jersey	Grid Modernization	June 2019
Virginia	Energy Storage	September 2019
Maryland	RPS / Energy Storage	December 2019

Regulators also concluded several investigatory efforts related to grid modernization. The New York Public Service Commission approved an energy storage roadmap during the quarter, which provides a pathway to achieving the state's energy storage target. An investigatory proceeding considering changes to resource planning and distribution system planning was completed in Colorado, although rulemakings stemming from the proceeding may be opened in 2019. The Connecticut Public Utilities Regulatory Authority concluded its investigation into distribution system planning and integration of grid modernization technologies, while the Illinois Commerce Commission published a draft of its final NextGrid report.

Box 4. Categorizing Studies and Investigations

Actions included within Studies and Investigations do not include a defined policy proposal or a directive to make a policy or regulatory change. Once a specific proposal is introduced, that action will be included in the more specific category pertaining to that particular type of change, such as Grid Modernization Planning, Utility Business Models, Rate Reforms, or the specific categories listed under Grid Modernization Policies, such as interconnection rules, changes to renewable portfolio standards, energy storage targets, and AMI rules.

Table 10. Updates on Grid Modernization Studies & Investigations (Q4 2018)

State	Type of Study	Description	Source
AR	Distributed Energy Resources, Grid Modernization	In November 2017, the Arkansas Public Service Commission expanded the scope of a generic proceeding on renewable distributed generation to more broadly consider policy changes related to DERs, as well as several specific AMI data access questions. In July 2018, the Commission issued an order, establishing a list of issues to be addressed during the course of the proceeding. These list includes many specific topics within the broader categories of DER aggregation, rate structure and rate design, low-income customer participation, advanced technology, and distribution system planning and integrated resource planning. The Commission will schedule an initial educational workshop on DER and grid modernization issues. The Commission accepted comments on the grouping of issues to be addressed in the proceeding and additional issues, the order and prioritization of these issues, means of addressing and building consensus on these issues, the expertise necessary to address these issues, and possible timeframes for events. The Commission also deferred action on the electric cooperatives' request for exemption from this proceeding until after the educational workshop.	Docket No. 16-028-U Order No. 10
AZ	Blockchain	In July 2018, the Arizona Corporation Commission opened a docket to investigate the role of blockchain technology in Arizona, at the request of Commissioner Tobin. No action has yet occurred in the docket.	Docket No. AU-00000A-18-0261
CA	Grid Modernization	California has an ongoing proceeding examining Distribution Resource Plans and the value of DERs to the distribution system. The proceeding was divided into three tracks, with Track 2 involving a range of demonstration projects to examine various location and technology scenarios, some of which include energy storage. In a February 2017 decision, the California Public Utilities Commission (CPUC) granted approval for some Track 2 demonstration projects, rejected others, and approved only some elements of other projects. The utilities filed revisions to their proposed projects, which the CPUC approved in June 2017. Track 3 is subdivided into 3 sub-tracks, with Sub-Track 2 concerning grid modernization investments. The CPUC issued a decision in March 2018 regarding Sub-Track 2. Specifically, the decision defines grid modernization, establishes a classification framework to serve as a common	Docket No. R. 14-08-013 Decision No. 18-03-023

		vocabulary for grid modernization investments, establishes the structure and timing of the grid modernization planning process, and provides guidance on how the CPUC will evaluate the cost-effectiveness of grid modernization investments. The decision also requires the utilities to submit Grid Modernization Plans in their general rate cases. In December 2018, an ALJ issued a ruling rejecting confidentiality claims that would have subjected some distribution system planning data to non-disclosure agreements.	
CO	Distribution System Planning	The Colorado Public Utilities Commission (PUC) opened a proceeding in October 2017 to consider changes to rules concerning the Renewable Energy Standard, net metering (including eligibility of solar-plus-storage customers), electric resource planning, acquisitions from qualifying facilities, and distribution system planning. The proceeding is serving as an information repository only; any rule changes will be undertaken in separate rulemaking proceedings. In early September 2018, parties submitted their final comments and proposed rule changes. The joint solar parties suggested requiring distribution system plans to include 25-year forecasts to account for the possibility of wider DER adoption. Western Resource Advocates suggested including evaluation of existing resources for possible retirement in electric resource plans. Xcel Energy opposed this suggestion, arguing that it would amount to retroactive review of previously approved investments, leading to administrative inefficiencies. Xcel also noted that it is already retiring coal assets at a fast pace. Xcel suggested that the Commission allow procurement of utility-scale resources outside of the electric resource planning process under certain circumstances. The proceeding was closed on October 31, 2018; the PUC indicated that it is considering a Notice of Proposed Rulemaking related to the suggestions from this docket.	Docket No. 17M-0694E
CT	Grid Modernization, Rate Reform	In November 2017, the Public Utilities Regulatory Authority (PURA) opened a proceeding to investigate the state of the electric distribution companies' distribution systems and plans, near and long term needs of the distribution system, and whether any new or modified planning objectives, metrics, solutions, performance incentives, oversight and/or procurement mechanisms should be implemented. Focus areas highlighted by the PURA include DER integration; modernizing data sensing, analytics, control, and communications; alternatives to traditional capacity solutions; and rate design. In March 2018, the PURA issued a Notice of Scope of Proceeding, outlining the scope of the first phase of	Docket No 17-12-03

		the proceeding. This first phase will focus on establishing the PURA's regulatory framework for grid modernization and examining three questions: (1) What are the key cost drivers associated with maintaining and modernizing the electric distribution system? (2) To what extent is customer electric demand changing in the near-term and long-term, and how can distribution system planning efforts best respond to changing customer demand? and (3) What functions do grid modernization technologies serve and how can these technologies be deployed to most effectively and efficiently meet the needs of the electric distribution utilities and customers, in light of the evolving distribution grid and electric system? A technical meeting was held in June 2018, focusing on Topic 1, while Topics 2 and 3 were addressed at technical meetings in July and October 2018. A public hearing was held in late October, and the PURA closed the record in the proceeding on November 26, 2018.	
DC	Grid Modernization	In June 2015, the DC Public Service Commission (PSC) initiated a proceeding to identify technologies and policies that can modernize its energy delivery system for increased sustainability, reliability, efficiency, cost-effectiveness, and interactivity. In January 2017, the staff presented its Modernizing the Distribution Energy Delivery System for Increased Sustainability (MEDSIS) report. In February 2018, the PSC adopted a MEDSIS vision statement and determined that it would conduct a request for proposals for a MEDSIS consultant. The PSC selected the Smart Electric Power Alliance (SEPA) to serve as its consultant. In June 2018, SEPA led a MEDSIS technical conference in which stakeholders were able to provide input on whether a system assessment was needed and what working groups should be formed in Phase 2 of the MEDSIS Initiative. SEPA filed its recommendations, which the Commission approved in an August 2018 decision. Specifically, SEPA recommended against a full system assessment at this time, and recommended the formation of six working groups: (1) Data and Information Access and Alignment, (2) Non-Wires Alternatives to Grid Investments, (3) Future Rate Design, (4) Customer Impact, (5) Microgrids, and (6) Pilot Projects. The MEDSIS website includes detailed information about the work to be conducted by each of the working groups and includes a schedule with meetings running through January 2019. A later decision, filed in September 2018 tasked the Non-Wires Alternatives working group with proposing a definition for "smart inverter" and considering utility	Formal Case No. 1130 MEDSIS website MEDSIS Staff Report Order No. 19432 (August 2018) Order No. 19692 (September 2018)

		ownership of DERs, like energy storage devices, and submit its recommendations for the Commission's consideration. Parties filed comments on the transportation electrification program, filed by Pepco as a part of this docket, during Q4 2018.	
HI	Utility Business Model	H.B. 1700 of 2016 appropriated funds for the Hawaii Energy Office to commission a study of alternative utility and regulatory models to enable the state to (1) meet its energy goals; (2) maximize consumer savings; (3) enable a competitive distribution system; and (4) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation. The Energy Office selected London Economics International, LLC to lead the project, and scheduled three rounds of community meetings in each of the counties. The first round of community meetings was held in mid-October 2017 and focused on the topic of utility ownership and the utility's role in meeting community and state goals. The second round of meetings were held in June 2018 and focused on utility regulatory models. The preliminary report is expected to be released in October 2018, with the final report planned to be released in January 2019.	H.B. 1700 (2016) Study Website
IL	Grid Modernization	In March 2017, the Illinois Commerce Commission opened the "NextGrid" proceeding following the passage of legislation in December 2016 that makes comprehensive changes to various aspects of Illinois energy policy. This is a collaborative process between stakeholders and involves a broad array of topics. Seven working groups have been established, each addressing topics potentially pertaining to grid modernization: (1) New Technology and Grid Integration, (2) Electricity Markets, (3) Customers and Community Participation, (4) Regulatory, Environmental, and Policy Issues, (5) Metering, Communications, and Data, (6) Reliability, Resiliency, and Cyber Security, and (7) Ratemaking. The NextGrid process officially began in late September 2017 with a kickoff conference in Chicago. The working groups submitted draft reports in August 2018, most of which contained discussions pertaining to grid modernization. Working Group 1's report discusses microgrids and distribution system planning. Working Group 2's report discusses AMI. Working Group 4's report discusses data access, time-varying rates, energy storage, and grid modernization impacts on very large customers. Working Group 5's report discusses real-time pricing and its interaction with advanced metering. Working Group 7's report discusses time-varying rates and performance-based regulation. A draft final report	Docket No. 17-0142 NextGrid Draft Final Report

		compiling the working group reports was published in December 2018, comments on the final report were published in early January 2019.	
KS	AMI Opt-Out	In May 2018, following several customer complaints related to AMI opt-out rules, the Kansas Corporation Commission directed Westar and Kansas City Power & Light to file new or updated tariffs allowing customers to opt out of AMI installation at the customer's expense. The Commission also opened a general investigation docket to fully investigate the parameters and intricacies of AMI opt-out programs in July 2018. Initial comments were due in November 2018, and a final order is expected by March 15, 2019.	Docket No. 15-WSEE-211-COM Order on Reconsideration Docket No. 19-GIME-012-GIE
LA	Demand Response, Rate Design	As part of Entergy Louisiana's IRP process, the utility commissioned ICF to conduct a study of the long-term achievable demand response potential in the utility's service territory. A stakeholder meeting was held in April 2018, where ICF gave a presentation on the study. ICF assessed several different types of demand response programs, including direct load control, interruptible load, curtailable load, automated demand response, TOU pricing, critical peak pricing, and real-time pricing. The final study was filed with Entergy's draft IRP in October 2018. The study finds that demand response programs can achieve savings of 5.3% of electricity demand by 2038 in the high case and 4% in the reference case. The study also finds that demand growth can be offset by 55% by 2038 in the high case and 41% in the reference case. ICF found that the programs are cost-effective in both the high and reference cases and that residential direct load control, residential TOU, and industrial TOU programs were the dominant programs, providing 87% of total savings modeled.	Docket No. I-34694 Entergy Louisiana: Analysis of Long-Term Achievable Demand Response Potential
	Grid Modernization	In February 2018, the New Orleans City Council opened an inquiry into establishing a smart cities initiative for the city and directing Entergy New Orleans to report on grid modernization matters. The Council's resolution directed Entergy New Orleans to file within 60 days a report detailing available grid modernization technologies and how such modernization could be implemented by the utility. The Council Utility Advisors are directed to prepare a report on other aspects of technology integration that could be achieved with a smart cities initiative. In April 2018, Entergy New Orleans filed its grid modernization report. The utility hired a third party to conduct an asset-specific engineering study evaluating 467 circuits across the Entergy system. Based on this study, Entergy New Orleans is	City Council Docket No. 18-01 Resolution No. R-18-536 Entergy New Orleans Grid Modernization Report

		developing five grid modernization projects to increase grid reliability, which will include the deployment of 537 smart devices (noted as regulators and capacitors) and 42 self-healing networks. The City Council approved a resolution on December 20, 2018 directing the Utility Advisors to propose a roadmap for achieving electric grid modernization and the Smart City initiative goals with a draft "Smart Audit" procedure. The resolution also merged Docket No. 18-02 regarding electric vehicles with the smart cities docket (Docket No. 18-01).	
MA	AMI	Resolve S. 1268 creates a special commission to examine the health impacts of electromagnetic fields from all sources, including utility smart meters. The Commission is to look at non-industry funded science research. The bill died at the end of the state's legislative session.	S. 1268 (D)
MD	Energy Storage	H.B. 773, enacted in May 2017, directs the Maryland Power Plant Research Program to conduct a study of regulatory reforms and market incentives that are necessary or beneficial to increase the use of energy storage devices in the state. The team submitted initial findings to the state legislature in January 2018. The initial findings review costs, benefits, obstacles, and policies. Some of the obstacles identified include the lack of a market for many of the benefits energy storage can provide to the entire system, the regulatory and operational ability for single storage systems to provide multiple benefits, current electricity rate structures, questions around the legal ability of utilities to own storage resources, current evaluation tools for grid investments, and uncertainty in the interconnection process for behind-the-meter storage. The final study was published in December 2018 (in PC 44). The report provides a comprehensive background about energy storage technologies and its potential applications in Maryland, as well as a variety of policy options the state could pursue. The report finds three policy options most relevant to Maryland to be (1) removing barriers by updating rate designs and regulations, (2) supporting storage through targets and/or incentives, and (3) taking a more active role in overseeing distribution system planning.	H.B. 773 (2017) Power Plant Advisory Committee Energy Storage Work Group Website Public Conference 44 Energy Storage in Maryland (Final Report)
	Energy Storage	H.B. 1414, enacted in May 2017, requires the Power Plant Research Program to conduct a study on the state's Renewable Portfolio Standard (RPS). The study will include a review of the program's history, implementation, overall costs and benefits, and several other issues. The bill also requires energy	RPS Study Work Group Website H.B. 1414 (2017)

	storage to be part of the study, specifically addressing whether energy storage should be encouraged through a procurement, production or installation incentive; the advisability of providing incentives for energy storage to increase the hosting capacity of renewable energy on-site; and the costs and benefits of energy storage under future goals scenarios. The study group has primarily focused two tasks to date, both of which are focused on the functioning of the current RPS. The study group issued an RFP in October 2017 to find a party to complete the remaining tasks in the study, including those related to energy storage. Though the RFP states that the contractor will rely principally on the energy storage study being prepared under H.B. 773 (see above). An interim report is due December 1, 2018 and a final report is due by December 1, 2019. A webinar was held in November 2018 to update parties on the progress of the study.	
Energy Storage	As part of Maryland's PC 44 grid modernization process, the energy storage working group filed a proposed Proof of Regulatory Concept Program to test different regulatory and business models for energy storage. An initial pilot program draft was circulated by the Energy Storage Association in July 2018, and the final proposal was filed in the docket in January 2019. In December 2018, the Maryland Energy Administration submitted a letter expressing concern with the pilot program design, and the joint utilities filed a letter expressing support for the proposed program. The program takes a "learning by doing" approach, where four different ownership and operational models will be tested: (1) a utility only model, where the utility owns and operate the asset; (2) a utility and third party model, where the utility owns the asset and has control of the system for grid reliability, while the third party operates the storage in wholesale markets; (3) a third-party ownership model, where a third party owns the asset and operates the storage in wholesale markets, while the utility has control for grid reliability; and (4) a virtual power plant model, where a customer or third party owns the asset, the utility via an aggregator or as an aggregator has control for reliability, and the utility and/or a third party as an aggregator operates the storage in wholesale markets.	Public Conference No. 44
Grid Modernization	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to ensure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. The	Public Conference No. 44

		proceeding is addressing rate design, electric vehicles, competitive markets and customer choice, the interconnection process, energy storage, and distribution system planning. The Public Staff has organized working groups to study (1) rate design, (2) competitive markets and consumer choice, (3) interconnection, and (4) energy storage. The interconnection working group submitted a report in November 2017, including recommendations to initiate a rulemaking proceeding. The rate design working group submitted a revised report detailing TOU rate pilots in February 2018, and the Commission approved TOU pilots in June 2018. The energy storage working group submitted a proposal in December 2018. Rulemakings related to the electric vehicles and competitive markets and customer choice working groups are also currently underway.	
ME	Non-Wires Alternatives	In 2015, Central Maine Power (CMP) filed its Portland area needs assessment, and as a follow-up to this report, the utility filed a report in February 2018 assessing transmission and non-transmission alternative solutions to address these needs. The report finds that a full non-transmission alternative solution is not feasible, but a hybrid transmission and non-transmission alternative solution is and could avoid $16.5 million in transmission upgrades. A conference was held in mid-July 2018, and in October, the Commission put the schedule on hold due to uncertainty around the upcoming publication of ISO-New England's Maine Needs Assessment and a possible re-examination of local transmission planning standards.	Docket No. 2011-0138
MI	Demand Response	In November 2018, the Michigan Public Service Commission opened this docket to investigate demand response aggregation issues, including: (1) whether the ability to aggregate demand response for customers of alternative energy suppliers (AES) for bidding into RTO markets should be limited to AES, or extended to non-AES third parties, (2) how to adequately track demand response resources being used for capacity demonstration purposes, (3) the appropriate treatment for aggregated demand response outside the capacity demonstration framework, and (4) appropriate reporting requirements for demand response and aggregation. Commission Staff is ordered to file a report on these issues by May 30, 2019.	Docket No. U-20348
	Energy Storage	In December 2018, the Michigan House adopted a resolution encouraging the Michigan Agency for Energy to undertake a stakeholder discussion on	H.R. 347 (Adopted)

		integrating energy storage into the state's electric market.	
	Interconnection	In November 2018, the Michigan Public Service Commission opened this docket to conduct an investigation of interconnection rules, legally enforceable obligations under PURPA, distributed generation (including energy storage), and legacy net metering rules. The interconnection working group met in early December 2018, and stakeholder meetings for each of the different subjects took place January 10-11, 2019.	Docket No. U-20344
MN	Demand Response	In July 2017, Minnesota Power filed for approval of its EnergyForward proposal. The EnergyForward proposal includes a combination of 250 MW of wind, 10 MW of solar, and 250 MW of dispatchable natural gas. During subsequent hearings, demand response was raised as a possible alternative to the 250 MW of natural gas. A demand response stakeholder group was formed and held workshops in September and November2018. In December 2018, Minnesota Power submitted a petition outlining a new suite of demand response products with associated cost recovery that it developed through the stakeholder process. The new products include a short-term emergency capacity product, a long-term emergency capacity curtailable with firm load control periods product, and a market surplus service capacity product.	Docket No. 17-568
	Grid Modernization	The Public Utilities Commission (PUC) opened a docket in May 2015 to consider the development of policies related to grid modernization. The proceeding features broad stakeholder engagement and numerous workshops. In April 2017, the PUC issued a request for comments from Xcel Energy, Minnesota Power, and Otter Tail Power (cooperative and municipal utilities were encouraged but not required to respond) related to the following questions: (A) How do Minnesota utilities currently plan their distribution systems? (B) What is the status of each utility's current plan? and (C) Are there ways to improve or augment utility planning processes? In April 2018, the Commission Staff released a briefing paper, setting forth a proposed procedure and schedule for developing utility-specific integrated distribution plans. According to the Staff's schedule, Xcel Energy and the Dakota Electric Association would have until November 1, 2018 to submit their integrated distribution plans, and Otter Tail Power and Minnesota Power would have until November 1, 2019. The PUC held a meeting in April 2018 to discuss the actions the Commission should take on distribution system	Docket No. 15-556

		planning for each of the utilities. An August 2018 order affirmed the integrated distribution planning (IDP) filing requirement for Xcel Energy, and the utility filed its IDP in November 2018 in Docket No. 18-251. The Commission opened a comment period for Xcel's IDP on November 19, 2018.	
	Rate Reform	The Public Utilities Commission (PUC) initiated a stakeholder proceeding in July 2015 to consider alternative rate designs for Xcel Energy. Workshops were held with presentations from various speakers about alternative rate design implementation across the country. In April 2017, Xcel Energy presented on its ongoing development of an alternative rate design pilot, and the PUC solicited comments on the pilot and whether this generic docket should continue in parallel to the Xcel pilot development. The PUC received comments from stakeholders during May 2017, and no parties appear to be opposed to Xcel developing a pilot, or leaving the current docket open after Xcel files its pilot program. Xcel is developing its alternative rate design pilot with a group of stakeholders, facilitated by the Great Plains Institute and the Center for Energy and Environment. In February 2018, the Great Plains Institute filed its notes from the stakeholder meetings, demonstrating that Xcel designed its TOU pilot in direct response to the requests, goals, and objectives of the stakeholders involved. No significant action took place in the second half of 2018.	Docket No. 15-662
MO	Distributed Energy Resources, Rate Reform	In March 2017, the Missouri Public Service Commission (PSC) opened a proceeding to gather information on issues including AMI installation, PACE financing programs, and alternative rate design proposals. A workshop was held in May 2017, where these issues were discussed. In July 2017, the Commission staff filed a report with recommended next steps. The report recommends that workshops be held to discuss several issues, including new rate designs, particularly time-of-use rates and inclining block rates. However, as no significant issues related to AMI were identified during the comment period or workshop, the staff did not recommend additional workshops on AMI. Workshops on DER issues were held in November 2017 and January 2018. In April 2018, the Commission Staff released a report on DER issues. The report states that distributed storage is eligible for inclusion in Missouri's demand-side management program, which would allow utilities to recover costs for distributed storage.	Docket No. EW-2017-0245 July 2017 Staff Report April 2018 Staff Report June 2018 Draft Rule

		In May 2018, the PSC Staff published a draft rule for comment, and a workshop was held to discuss the rule. In late June 2018, the PSC Staff filed an updated version of the draft rule for comment. The current version requires utilities to maintain a database of current DERs on their grids, assess the market potential for DERs as part of their triennial compliance filings, and evaluate DERs as part of the resource planning process, including their integration with the transmission and distribution system. Several parties filed comments on the draft rule in July 2018. The Office of the Public Counsel argued against the need for the new rules, stating that current rules are sufficient and arguing that the database would be created too late to help inform current policy deliberations. The Division of Energy from the Missouri Department of Economic Development and Renew Missouri generally supported the draft rules, and made suggestions to include additional elements in the required analyses. The comments jointly submitted by utility parties suggested using a different definition for cost-effectiveness (the draft rules use a definition from the National Efficiency Screening Project, while the utilities suggest using the definition from the Missouri Energy Efficiency Investment Act of 2009) and suggest providing information on current DERs on the grid through annual filings rather than an online database. Action in this docket during the second half of 2018 focused on standard offer rules under PURPA; no further action was taken on the DER or AMI issues.	
MT	Grid Modernization	In April 2018, NorthWestern Energy held the first meeting of its Customer Vision stakeholder group. The group will address potential products and services customers would be interested in, pricing models that align utility and customer needs, and the future of the power grid. The group also met in May, June, and September 2018, with presentations about Minnesota's e21 Initiative, the Illinois NextGrid process, and Green Mountain Power's programs. An October 2018 meeting discussed Ontario's electricity pricing and rate design, as well as NorthWestern Energy's infrastructure initiative goals and alternatives. A meeting was held on November 30th to discuss a decoupling proposal and force-field analysis. The next meeting is scheduled for February 1, 2019, with presentations on decoupling, energy efficiency opportunities, providing a true customer experience, and keeping customer focus in technology projects.	Customer Vision Stakeholder Group
NC	Energy Storage	H.B. 589, enacted in July 2017, directs the North Carolina Policy Collaboratory at UNC Chapel Hill to	H.B. 589 (2017)

		conduct a study on energy storage. The study is to address how energy storage technologies may or may not provide a benefit to North Carolina consumers based on a number of factors, the feasibility of storage in the state, and policy recommendations for energy storage. The Collaboratory selected a team of researchers at North Carolina State University to conduct the study. Stakeholder meetings were held in February, June, and October 2018. A draft report on the current North Carolina policy and regulatory context for energy storage was released in September 2018. The final report was submitted to the North Carolina General Assembly in early December 2018. The report quantifies the value of different services provided by energy storage technologies and includes a menu of policy options, broken out into three categories: Prepare, Facilitiate, and Accelerate.	NC Policy Collaboratory Website NC Energy Storage Study Website Energy Storage Options for North Carolina (Final Report)
NJ	Energy Storage	A.B. 3723, enacted in May 2018, directs the Board of Public Utilities, in consultation with PJM Interconnection and stakeholders, to conduct an energy storage analysis. The study is to address a number of specific questions, quantify the potential costs and benefits of increasing energy storage and DERs in the state, and recommend ways to increase energy storage and DERs in the state. The Board of Public Utilities announced in October 2018 that it hired Rutgers University to conduct the study. The New Jersey Energy Storage Stakeholder Group is scheduled to hold a meeting on February 15, 2019 at Rutgers University. The Rutgers team (Rutgers University Laboratory for Energy Smart Systems) will introduce the approach to meet the state's target of 2 GW of storage by 2030.	Energy Storage Working group Docket No. EO18101123 (not available online) A.B. 3723 (E) Press Release
	Grid Modernization	In May 2018, New Jersey's Governor directed the Board of Public Utilities to develop the 2019 Energy Master Plan. As part of this process, a stakeholder meeting on Building a Modern Grid was held in September 2018. Some of the topics being addressed by the Building a Modern Grid stakeholder group include the most critical steps and barriers to grid modernization, resource planning, integrated distribution planning, reliability and resiliency, performance metrics, rate design and tariff structures to support grid modernization, managing grid modernization costs, use of new technologies, role of AMI, data access, distribution monitoring systems, physical security and cybersecurity, and economic development and environmental justice issues related to grid modernization. The final plan is expected to be completed in June 2019.	Executive Order No. 28 Press Release Energy Master Plan Website

	Microgrids	A.B. 3931, introduced in May 2018, directs the Board of Public Utilities to study whether microgrids and electric generators assist in reducing the length of long-term power outages in the state. The study is also to provide recommendations to improve the resilience and reliability of the state's electric distribution system. The study would be due within six months of enactment of the bill.	A.B. 3931 (I)
NM	Regulatory Reform, Utility Business Model	In March 2017, the New Mexico Public Regulation Commission initiated an investigation to determine whether it should standardize or change its ratemaking policies. Specifically, the Commission is requesting information related to developing a standardized method for determining return on equity (ROE), whether ROE should be adjusted under an incentive/disincentive mechanism, providing access to proprietary software used by utilities to support positions in rate cases to all intervenors and staff, defining regulatory assets, and recovery of certain regulatory case expenses. Public workshops were held in September and November 2017, and the workgroup reports were submitted in January 2018. A public workshop was held in July 2018.	Docket No. 17-00046-UT
NV	Blockchain	The Public Utilities Commission of Nevada opened a new docket in September 2018 at the request of Commissioner Pongracz. Specifically, the Commissioner requested an investigation on blockchain, and whether it could be used to better track portfolio energy credits associated with the state's Renewable Portfolio Standard.	Docket No. 18-09008
	Energy Storage	S.B. 204, enacted in May 2017, requires the Public Utilities Commission of Nevada (PUCN) to determine whether it is in the public interest to adopt annual requirements for the procurement of energy storage by utilities. In making the determination, the PUCN must study all measurable costs and benefits. In July 2017, the PUCN opened a docket to implement the legislation, and workshops were held in November 2017 and February 2018. The PUCN also held a teleconference in November to discuss a proposal from Tesla for a third-party to study the costs and benefits of storage in Nevada. The teleconference participants agreed on a process and schedule for determining the scope of work for a third-party study. The Governor's Office of Energy issued the 2018 Nevada Energy Storage Study RFP in February 2018, and later selected the Brattle Group to conduct the study. The Brattle Group submitted its energy storage study in early October 2018. The study finds that by	Docket 17-07014 S.B. 204 (2017) The Economic Potential for Energy Storage in Nevada (The Brattle Group)

		2020 up to 175 MW of utility-scale battery storage could be deployed cost-effectively statewide, increasing to 700 MW - 1,000 MW by 2030. Additionally, behind-the-meter storage could add up to 30 MW of storage capacity by 2030. In December 2018, the Commission issued an order accepting the report and its recommendation to proceed to a rulemaking phase to develop a regulation establishing an energy storage target.	
NY	Energy Storage	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. The Roadmap does not contain policy changes itself but makes many recommendations on policy actions that could be undertaken in related proceedings. Three technical conferences to discuss the Roadmap were held in July and August 2018. In September 2018, the Public Service Commission (PSC) issued an environmental impact statement for the Roadmap, finding significant positive environmental impacts from the recommended policy actions in the Roadmap, with minimal adverse impacts. Public hearings were held in October 2018. In December 2018, the PSC adopted an energy storage target and roadmap for deploying 1,500 MW of storage by 2025 and 2,000 MW by 2030. The PSC also directed the Commission Staff to study how many MWs of peaking units could be economically replaced or repowered with energy storage without harming reliability. The Commission Staff and NYSERDA are also to develop a work plan for the Market Design and Integration Working Group by March 2019. The Staff is also to file a white paper by July 2019 on the environmental value component of the Value of Distributed Energy Resources (VDER) tariff for storage resources.	Docket No. 18-00516/18-E-0130 NYSERDA Website
	Energy Storage	In late June 2018, the New York Green Bank issued a Request for Information on financing arrangements for energy storage projects in New York. Responses were accepted until the end of December 2018.	RFI: Financing Arrangements for Energy Storage Projects
	Grid Modernization	The "New York Grid Modernization Act" (A.B. 7480) establishes a Smart Grid Advisory Council, which would be tasked with conducting a study on the feasibility of establishing a statewide smart grid system. The smart grid system envisioned would include AMI, incorporate consumer products, promote DERs, and protect privacy and security.	A.B. 7480 (D)

	The comprehensive bill includes provisions for cost allocation, workforce development, low-income programs, and more. The bill died at the end of the legislative session.	
Microgrids	A.B. 6134 directs the New York Public Service Commission to develop recommendations regarding the establishment of microgrids in the state. Specifically, the Commission is to submit a report with recommendations on: (1) the use of microgrids for critical infrastructure facilities, (2) prioritization of certain geographical areas based on the probability of storm damage, and (3) funding mechanisms to pay for microgrid projects. The bill died at the end of the legislative session.	A.B. 6134 (D)
Rate Reform	In May 2017, as part of the Public Service Commission's (PSC) Reforming the Energy Vision Track Two order, the PSC directed the Commission Staff to publish a report regarding scope, feasibility, and deliverables on an analytical approach to examining bill impacts of a range of opt-out variable rate scenarios (i.e. time-varying rates, demand charges, coincident-peak demand charges) for residential and commercial customers. In October 2017, the staff published its scope of a study to examine bill impacts. The staff will consider rate design structures, billing determinants, and calculate revenue-neutral rates based on the PSC's rate design principles. In January 2018, the Staff provided further guidance for utilities to guide the bill impact study. The Staff published a draft outline for a standby/buyback white paper in February 2018. The outline includes a recommendation to require utilities to develop more granular As-Used Demand charges, which have time and location-variant components, depending on the cost driver of the distribution system. In December 2018, the PSC Staff published a white paper recommending modifications to the existing standby and buyback service rates. The paper recommends the Commission direct the utilities to submit draft tariffs for standby service rates based on the individual customer's maximum demand using the interval data provided by AMI. While previously, the standby tariffs were designed using extended period of billing data, the paper asserts that using AMI data, the standby rates can be better designed to offer accurate price signals. These standby rates do not affect net-metered customers, but may impact other DG systems that are not eligible for net metering and currently pay standby or buyback rates.	Docket No. 17-01277

	Rate Reform	A.B. 8817, introduced in November 2017, requires the Public Service Commission to publish a report on residential customer savings realized through time-of-use tariffs and smart meters. The report should include: (1) the total number of customers enrolled in time-of-use tariffs, (2) the total number of smart meters installed, (3) the total cost incurred, (4) the total savings, and (5) the impact of the time-of-use rates on carbon emissions, customer behavior, and outages. The bill died at the end of the legislative session.	A.B. 8817 (D)
OH	Grid Modernization	The Public Utilities Commission of Ohio (PUCO) announced the launch of its PowerForward grid modernization investigation in March 2017. The purpose of the investigation is to chart a path forward for future grid modernization projects and innovative regulations that can improve the consumer experience. The PowerForward investigation included three phases: Glimpse of the Future, Exploring Technologies, and Regulation. In August 2018, PUCO released its final PowerForward Roadmap. The Roadmap provides a vision for the modernization of Ohio's grid and includes a series of recommended next steps to implement the vision. PUCO established separate dockets for the PowerForward collaborative and its spinoff workgroups (one on distribution system planning and one on data and the modern grid) in October 2018. As a first step in November 2018, the Attorney Examiner requested that each electric distribution company file its most recent update of where it stands on grid architecture. Additionally, parties are to provide comments on the proposed grid architecture status reporting and the proposed filing date of April 1, 2019. A PowerForward Collaborative meeting was held on December 6, 2018, which featured several presentations related to electric vehicles. The next meeting is scheduled for February 14, 2019.	Docket No. 18-1595-EL-GRD (PowerForward Collaborative) PowerForward Website PowerForward Roadmap
PA	Grid Modernization	In July 2018, the Pennsylvania Department of Environmental Protection published a draft for public review of its Finding Pennsylvania's Solar Future report. The draft report recommends that the state investigate opportunities for grid modernization to enable increased solar generation. Comments on the draft were accepted until mid-August 2018, and the final plan was published in November 2018. The final report includes the same recommendation as the draft regarding grid modernization.	Finding Pennsylvania's Solar Future

Rate Reform, Utility Business Model Reform	In December 2015, the Pennsylvania Public Utility Commission (PUC) opened a proceeding to investigate alternative ratemaking methodologies. The PUC issued an order in March 2017, requesting further input from stakeholders on their experiences with different types of alternative rate methodologies, including decoupling, lost revenue adjustment mechanisms, straight fixed/variable pricing, surcharges and riders, choice of test years, multiyear rate plans, demand charges, standby and backup charges, and demand-side management performance incentives. The PUC also accepted comments regarding whether it should adopt policy statements identifying preferred alternative rate methodologies or initiate rulemakings to require specific methodologies. In May 2018, the PUC published a proposed policy statement. The statement includes 13 considerations for determining just and reasonable distribution rates that encourage efficiency and the use of DERs. These considerations are: (1) How rates align revenues with cost causation principles, (2) How rates impact the fixed utility's capacity utilization, (3) Whether the rates reflect the customer's demand, (4) How the rates limit or eliminate inter-class and intra-class cost shifting, (5) How the rates limit or eliminate disincentives for efficiency, (6) How the rates impact customer incentives for efficiency and DER use, (7) How the rates impact low-income customers, (8) How the rates impact customer rate stability principles, (9) How weather impacts utility revenue under the rates, (10) How the rate impact the frequency of rate case filings and regulatory lag, (11) How the rates interact with other surcharges and riders, (12) Whether the rate mechanism includes appropriate consumer protections, and (13) Whether the rate mechanism is understandable and acceptable to consumers. The statement specifically authorizes electric distribution utilities to propose critical peak pricing or similar demand-based programs using average usage over critical peak periods. These types of programs are to include a fixed charge that reflects metering, final line transformer, and service drop costs, a critical peak volumetric or average demand component that reflects usage over distribution system components during localized peak usage periods, and a volumetric on-peak, off-peak or other type of rate for other costs. The deadline for comments on the proposed policy statement was extended to October 22nd, with reply comments due November 20th.	Docket No. M-2015-2518883 Proposed Policy Statement
Time-Varying Rates	As part of a settlement filed in September 2018 in Duquesne Light Company's general rate case, the utility agreed to hold two non-confidential	Docket No. R-2018-3000124

EXHIBIT 4

		collaboratives with stakeholders on residential TOU rates. Duquesne is also to file a TOU rate proposal in its next default service rate filing, unless the Commission directs the utility to do so sooner. The Commission issued a final order in December 2018, approving the settlement agreement, including the TOU provisions.	Settlement Agreement
RI	Demand Response	In October 2018, National Grid filed its 2019 System Reliability Procurement Report. In the report, the utility proposed a Customer-Facing Program Enhancement Study to develop and test new customer engagement approaches for demand response.	Docket No. 4889 2019 System Reliability Procurement Report
SC	Energy Storage	In September 2018, the Public Service Commission announced an ex parte briefing to be held in October 2018 concerning avoided cost, resource planning and energy storage in an era of low-cost solar.	ND-2018-23-E
	Energy Storage, Grid Modernization, Rate Reform	In May 2018, the South Carolina Legislature's Public Utilities Review Committee tasked the Energy Office with leading a stakeholder process to look broadly at the future of electricity in the state within the context of Act 236 and with a particular focus on renewable energy. Approximately 50 stakeholders are part of the process, and seven meetings have taken place since June 2018. A wide variety of issues have been considered by the group including rate design, grid modernization, and energy storage. The group held a meeting in October 2018, which included presentations on battery storage.	Stakeholder Group Website
VA	Energy Storage	The FY 2019 budget bill allocated funds to the Department of Mines, Minerals and Energy to commission a study and provide recommendations for advancing energy storage in Virginia. Specifically, the report will include a comprehensive and quantitative benefit-cost analysis of energy storage in Virginia, including an analysis of the benefits of various levels of energy storage adoption across the generation, transmission, and distribution systems. The study will also explore the federal and state regulatory barriers and incentives for energy storage, the economic benefits of storage that are unique to Virginia, and current best practices concerning safety. The Department released an RFP for a contractor to conduct the study in September 2018. In December 2018, it was announced that Strategen Consulting was hired to conduct the study. The study is to be completed by September 15, 2019.	Request for Proposals

VT	Grid Modernization, Utility Business Model	In June 2017, the Vermont Public Utility Commission (formerly the Public Service Board) opened an investigation into utility regulation in the state, following a request from the Department of Public Service. Specifically, the Commission is reexamining Vermont's regulatory structure in response to recent transformations in technology, state policy, and other areas. The proceeding is divided into four topic areas: (1) principles of rate regulation, (2) rate design, (3) grid impacts, and (4) municipal and cooperative utility issues. Two workshops were held in August and September 2017. The first workshop focused on the scope and framework for the proceeding, while the second workshop focused on non-traditional forms of regulation used outside of Vermont and variations in the way traditional regulation is used in other jurisdictions. A third workshop was held in early October, addressing the merits and disadvantages of traditional and alternative forms of regulation. In December 2017, the Department of Public Service filed its recommendations on future alternative regulation plans. The Department identified five goals for alternative regulation: (1) maintain affordability and spur economic development, (2) offer accessibility and transparency, (3) align utility and customer interests, (4) accommodate different types of utilities, and (5) include appropriate timeframes for review. The Department also recommended that the PUC issue an order refining the requirements for alternative regulation, based on statutory criteria. The Department's recommendations outline the statutory requirements for alternative regulation, as well as other plan features that may be considered, including decoupling, multi-year rate plans, performance incentive mechanisms and metrics, a fuel or power adjustment clause, exogenous adjustments, earnings sharing, and new businesses and third-party access. The Commission issued an order in July 2018, providing principles and considerations for future alternative regulation plans. These principles and considerations include advancement of state energy policy, open participation and transparency, fair balance of risks and rewards, just and reasonable rates, and service quality.	Docket No. 17-3142-PET Media Release

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of late January 2019.

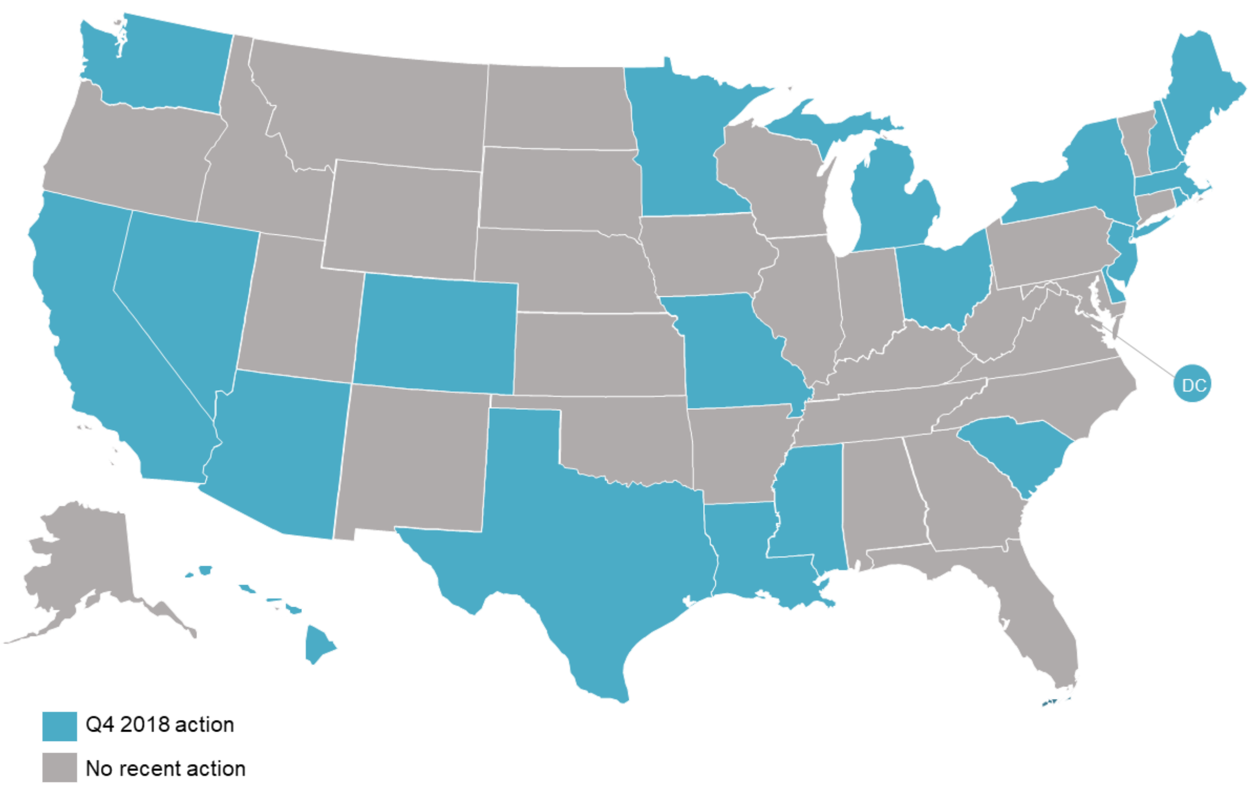
PLANNING AND MARKET ACCESS

Key Takeaways:

- In Q4 2018, 20 states plus DC considered changes to utility planning processes and state regulations enabling market access.
- ISOs/RTOs filed plans to comply with FERC Order 841 enabling energy storage participation in wholesale markets in December 2018.
- The Public Utilities Commission of Ohio opened a proceeding on distribution system planning, and Xcel Energy filed its integrated distribution plan in Minnesota.

As the potential roles for energy storage and other distributed energy resources within our energy system grow more important, policymakers and regulators are working to revise both wholesale market rules and planning methods to ensure these resources are appropriately considered in utility planning. In Q4 2018, 20 states and DC considered revisions to planning processes or market access rules related to grid modernization.

Figure 30. State Action on Planning and Market Access (Q4 2018)



One area receiving particular attention during the quarter was distribution system planning rules. The Public Utilities Commission of Ohio opened a new docket focused on distribution system planning as part of its PowerForward grid modernization efforts. Duke Energy Carolinas and Duke Energy Progress presented, as part of their proposed Grid Improvement Plan filed in general rate cases in South Carolina, the Integrated System Operations Planning (ISOP) process the utilities are developing. The ISOP process is intended to combine generation, transmission, distribution, and customer program planning into one coordinated process. Meanwhile, Xcel Energy in Minnesota filed its integrated distribution plan and hosting capacity study.

Another important topic addressed during Q4 2018 was wholesale market rules governing the participation of energy storage resources. In December 2018, independent system operators (ISOs) and regional transmission organizations (RTOs) filed their plans to comply with Federal Energy Regulatory Commission (FERC) Order 841. Order 841, issued in February 2018, requires wholesale market operators to revise rules and tariffs to all energy storage resources to fully participate in energy, capacity, and ancillary services markets.

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Table 11. Updates on Planning and Market Access (Q4 2018)

State/RTO	Sub-Topic	Description	Source
AZ	Integrated Resource Planning	In August 2016, Arizona Corporation Commission Chairman Little opened a docket to review, modernize, and expand Arizona's Renewable Energy Standard and Tariff. In late January 2018, Commissioner Tobin filed his proposed Energy Modernization Plan. The proposed plan includes amending the state's integrated resource planning rules to support and promote the other policies within the proposed Energy Modernization Plan, including an energy storage target and clean peak target. In February 2018, the Commission Staff issued a Notice of Inquiry, soliciting comments on many specific questions related to Commissioner Tobin's proposal. In early July 2018, Commissioner Tobin filed a formal set of draft rules implementing his proposed Energy Modernization Plan. Later in July, several Commissioners expressed support for opening a new rulemaking docket to consider changes to the state's Renewable Energy Standard and Commissioner Tobin's Energy Modernization Plan. In August 2018, the Commission opened a rulemaking docket to evaluate modification to several different energy rules (see Docket No. RU-00000A-18-0284).	Docket No. E-00000Q-16-0289 Proposed Energy Modernization Plan Notice of Inquiry Draft Rules
	Integrated Resource Planning	In May 2018, the Arizona Corporation Commission opened a docket to modify the state's resource planning and procurement rules. No action occurred during Q3 or Q4 2018.	Docket No. RE-00000A-18-0137
	Integrated Resource Planning	In August 2018, the Arizona Corporation Commission opened a rulemaking docket to evaluate proposed modifications to many of the state's energy rules. Rules to be addressed in the proceeding include the renewable energy standard, energy efficiency standards, resource planning and procurement, retail electric competition, net metering, electric vehicles, DG interconnection, blockchain technology, technological developments, forest bioenergy, baseload security, and the biennial transmission assessment. No action related to integrated resource planning has yet occurred.	Docket No. RU-00000A-18-0284
CA	Distribution System Planning, Non-Wires Alternatives	California has an ongoing proceeding to investigate methods integrating DERs. The scope of the proceeding includes: (1) the development of a competitive solicitation framework for DERs, (2) the continued development of technology-neutral cost-effectiveness methods and protocols, (3) leveraging the work performed in the Distribution Resource Plans (DRP) proceeding (see Studies and Investigations), and (4) the role of the utilities, business models, and financial interests with respect to DER deployment.	Docket No. R-14-10-003

		A December 2016 decision established a Competitive Solicitation Framework and a Utility Regulatory Incentive Pilot for the procurement of DERs that displace or defer the need for investments in traditional distribution infrastructure. A Scoping Memo filed in February 2018 added two additional issues to the proceeding: alternative sourcing mechanisms or approaches that satisfy distribution planning objectives; and the ways in which existing programs, incentives, and tariffs can be coordinated to maximize the locational benefits and minimize the costs of DERs. The Commission accepted comments and reply comments on the new issues through April 2018. In November 2018, San Diego Gas and Electric (SDG&E) filed an evaluation report on its Streamlined Competitive Solicitation Framework and Utility Regulatory Incentive Mechanism pilot. The report indicates that SDG&E launched its Pilot Request for Offers in January 2018 and did not receive any conforming bids that were cost effective. The report presents a series of recommendations for improving the process, and the Commission opened a comment period on the report.	
	Resilience Planning	In October 2018, the California Public Utilities Commission opened a rulemaking proceeding related to S.B. 901 (enacted in 2018) regarding electric utility wildfire mitigation plans. The utilities will be filing wildfire mitigation plans in February 2019, which may include grid modernization investments. A prehearing conference was held in November 2018, and the Commission established a schedule for the proceeding in early December 2018. On December 27, 2018, a ruling was issued requiring the utilities to submit their wildfire mitigation plan templates by January 3, 2019. Evidentiary hearings will begin in March 2019.	Docket No. R-18-10-007
	Resilience Planning	S.B. 1088 directs each electrical corporation to submit a safety, reliability, and resiliency plan every two years, beginning January 15, 2019. The bill passed the Senate in May 2018, but died at the end of the legislative session.	S.B. 1088 (D)
CA / CAISO	Wholesale Market Rules	A.B. 813 requires a California transmission owner or utility to receive approval from various state bodies before participating in a multistate RTO. The bill further outlines requirements that regional RTOs must meet to be eligible for participation by a California transmission owner or utility. The bill passed the Assembly in June, but died in the Senate.	A.B. 813 (D)
	Wholesale Market Rules	A.B. 2787, introduced in February 2018, requires California ISO (CAISO) to procure between 1,000 MW	A.B. 2787 (D)

	and 2,000 MW of long duration energy storage projects by December 31, 2019. The bill also requires the ISO to develop a methodology for allocating the cost of that procurement to all load-serving entities within the CAISO-controlled electrical grid. The bill passed the Assembly in May 2018, but died in the Senate.	
Wholesale Market Rules	The California Public Utilities Commission (CPUC) is working to integrate demand response into the California ISO market, and is investigating whether a competitive procurement mechanism for supply-side resources outside of traditional utility programs is viable. An initial pilot auction was conducted in 2015 with delivery in 2016, and a second auction took place in 2016 with delivery expected in 2017. The CPUC later approved a third pilot auction in 2017. OhmConnect filed a request for the evaluation of the pilot programs to be expedited so the demand response auction mechanism could be made permanent by Summer 2018. In April 2017, the CPUC issued a decision denying OhmConnect's request and the request of the joint demand response parties. However, the decision left the door open for an additional auction in 2018 with delivery in 2019. A proposed decision issued in September 2017 declined to approve an additional auction, but an alternate proposed decision also issued in September did authorize an additional pilot auction. The issue was resolved with an October 2017 decision approving a 2018 auction for 2019 deliveries. The decision also established two working groups, a Supply Side Working Group and a Load Shift Working Group. A petition for modification was filed in January 2018, asking the CPUC to modify an October 2016 decision that adopted guidance for future demand response portfolios. Specifically, the petition asks the CPUC to clarify that the decision's resource prohibition does not apply to energy storage and suspend any requirements for energy storage used for demand response to meet the Self-Generation Incentive Program's (SGIP) greenhouse gas emissions standard. A June 2018 order grants in part the petition for modification, clarifying that energy storage not coupled with fossil fuel-fired generation is exempt from the list of prohibited resources. In doing so, the CPUC removed the requirement that storage had to meet the SGIP's greenhouse gas standard. The order closed the proceeding. In July 2018, Southern California Edison filed a petition for modification on behalf of all workshop participants. The petition seeks to modify a November 2017 decision, to clarify the implementation steps for the	Docket No. R-13-09-011 Proposed Decision Alternate Proposed Decision Decision No. 18-06-012

		Competitive Neutrality Cost Causation Principle. The proceeding has been re-opened.	
CAISO	Non-Wires Alternatives, Wholesale Market Rules	California ISO (CAISO) launched a new initiative in March 2018 concerning storage as a transmission asset. CAISO plans to use the initiative to examine methods for enabling storage providing cost-based transmission services to also participate in ISO markets and receive market revenues to provide ratepayer benefits. CAISO received a number of comments after releasing its Issue Paper in March, and held a web conference before releasing its Straw Proposal in May 2018. CAISO received numerous comments on the Straw Proposal and followed up with stakeholder meetings in May and June. The Straw Proposal provides two cost recovery mechanisms: full cost-of-service based cost recovery and energy market crediting, and partial cost-of-service based cost recovery and no energy market crediting. CAISO released a Revised Straw Proposal in August and a second Revised Straw Proposal in October. A stakeholder meeting scheduled for December 17, 2018 was postponed; a web conference has been scheduled for January 14, 2019.	SATA Initiative Website Second Revised Straw Proposal
	Wholesale Market Rules	California ISO's (CAISO) Energy Storage and Distributed Energy Phase 2 initiative is examining ways to enhance the ability of ISO-connected and distribution-connected resources to participate in the ISO market. Among the resources considered in this initiative are energy storage, plug-in electric vehicles, and demand response. Phase 2 of the initiative explored alternative baselines, distinguishing between charging energy and station power, and a net benefits test for demand response resources. Phase 3 was launched in September 2017 with the release of an Issue Paper outlining some of the concepts that will be discussed in the coming months. Phase 3 work continued in Q1 2018 with the release of a straw proposal in February. The straw proposal refined the scope of Phase 3 and included an initial set of solutions. The scope of Phase 3 includes new bidding and real-time dispatch options for demand response, the removal of the single load-serving entity aggregation requirement, the development of a load shift product, and the recognition of sub-metered electric vehicle supply equipment curtailment. A working group meeting was held in March 2018 to discuss the straw proposal, and a draft final proposal was released in July. A web conference was held in July to discuss the draft final proposal. The CAISO's Board of Governors approved the proposal in September 2018.	ESDER Initiative Website Issue Paper Straw Proposal Draft Final Proposal

	Wholesale Market Rules	In December 2018, California ISO (CAISO) submitted a tariff filing to FERC in order to comply with Order 841. The tariff adds storage to the definition of participating resources and allows storage resources with 100 kW or more of capacity to participate in CAISO markets (the minimum capacity for other resources is 500 kW). The tariff also exempts storage resources from access charges for withdrawing energy from the CAISO grid.	FERC Docket No. ER19-468
CO	Distribution System Planning, Integrated Resource Planning, Non-Wires Alternatives	In March 2018, Colorado lawmakers introduced a bill requiring the Public Utilities Commission (PUC) to establish rules for the procurement of energy storage by IOUs. The rules need to consider factors such as grid reliability and reduction of peak demand. The Governor signed the bill into law in June 2018, and the PUC opened a proceeding to implement the bill's requirements in September 2018. In November 2018, the PUC adopted a rule requiring the consideration of energy storage in electric resource planning, as well as transmission and distribution planning.	Docket No. 18R-0623E H.B. 1270 (E)
DC	Distribution System Planning, Non-Wires Alternatives	As introduced, this bill establishes the Distributed Energy Resources Authority, an independent authority that has a separate legal existence within the District government. The Authority's duties would include the following: (1) identify policies that may reduce monthly utility bills for consumers, (2) increase the efficiency and reliability of the distribution system through an independent stakeholder-driven planning process, (3) improve distribution system planning for underserved communities, and (4) grow the local energy economy by deploying competitively procured non-wires alternatives solutions to meet the energy needs of the District. The bill was introduced in April 2018.	B22-0779 (I)
	Non-Wires Alternatives	In June 2015, the DC Public Service Commission (PSC) initiated a proceeding to identify technologies and policies that can modernize its energy delivery system for increased sustainability, reliability, efficiency, cost-effectiveness, and interactivity. In January 2017, the staff presented its Modernizing the Distribution Energy Delivery System for Increased Sustainability (MEDSIS) report. In February 2018, the PSC adopted a MEDSIS vision statement and stated that it would conduct a request for proposals for a MEDSIS consultant. The Commission selected SEPA in June 2018 to serve as the consultant. SEPA led the MEDSIS Technical Conference in which stakeholders were able to provide input on whether a system assessment was needed and what working groups should be formed in Phase 2 of the MEDSIS Initiative. SEPA filed its recommendations, which the Commission approved in an August Decision.	F.C. 1130 MEDSIS website

		Specifically, SEPA recommended against a full system assessment at this time, and recommended the formation of six working groups: (1) Data and Information Access and Alignment, (2) Non-Wires Alternatives to Grid Investments, (3) Future Rate Design, (4) Customer Impact, (5) Microgrids, and (6) Pilot Projects. A later decision, filed in September 2018 tasks the Non-Wires Alternatives working group with proposing a definition for "smart inverter" and considering utility ownership of DERs like energy storage devices, and submitting its recommendations for the Commission's consideration.	
DE	Distribution System Planning	In April 2018, Delmarva Power, the Public Advocate, and the Public Service Commission Staff signed a memorandum of understanding agreeing to work together to develop a proposal on enhanced distribution system planning. In early July 2018, the Commission opened a docket to develop distribution system planning rules for electric, natural gas, and water utilities. The first meeting was held in July 2018, and joint recommendations from Delmarva, the Public Advocate and Commission Staff are due by September 1, 2019. No action took place in Q4 2018.	Docket No. 18-0935
FERC (All ISOs & RTOs)	Wholesale Market Rules	In January 2018, the Federal Energy Regulatory Commission (FERC) opened a docket on grid resilience and requested that the ISOs and RTOS submit responses regarding the development of a common understanding of resilience, how the ISOs/RTOs assess threats to resilience, and how the ISOs/RTOs mitigate threats to resilience. The PJM Interconnection filed comments in March 2018, arguing that FERC should require the various market operators to make changes to their tariffs in order to price resilience attributes; the remaining five regional grid operators filed comments arguing against such a change. While many of the issues focused on by commenters pertain to the resilience aspects of different electricity generation sources (i.e. nuclear, coal, gas, renewables), some commenters have discussed the resilience aspects of grid modernizing technologies, such as energy storage, improved grid communications, and transmission/distribution automation.	Docket No. AD18-7
HI	Distribution System Planning, Integrated Resource Planning, Non-Wires Alternatives	The HECO companies filed their Integrated Grid Planning Report with the Commission in March 2018. The Report proposes the merger of three separate planning processes; generation, transmission, and distribution, with the goal of identifying system-wide needs, coordinating solutions, and developing an optimized portfolio of assets. The Report also proposes a stakeholder process to develop the planning process, starting with the formation of a	Docket No. 2018-0165 Integrated Grid Planning Report Integrated Grid Planning Workplan

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		working group to assist in the development of the forecasts and input assumptions that will drive the planning process. The stakeholder process continues with the identification of the resource, transmission, and distribution needs, and the methods through which these needs will be acquired. The Commission opened a new proceeding in July to examine the Grid Planning Report. In December 2018, the HECO companies submitted their Integrated Grid Planning Workplan, which describes the process the utilities would go through in developing their integrated grid plans and the methods of stakeholder engagement.	
ISO-NE	Wholesale Market Rules	In October 2018, ISO-New England (ISO-NE) filed proposed revisions to its Transmission, Markets, and Services Tariff to allow energy storage technologies to more fully participate in the ISO-NE markets. The revised rules allow storage facilities capable of rapidly (10 minutes or less) and continuously (able to be dispatched to any level between maximum consumption capability and maximum generation capability) transitioning between consumption and generation to avoid the commitment process. The revisions also create a platform to allow for the provision of regulation services. The revisions will help the ISO comply with FERC Order 841, but will not include all of the new elements required for compliance with the order. The revisions are to become effective April 1, 2019.	FERC Docket No. ER19-470 ISO-NE Filing
LA	Integrated Resource Planning	As part of the Public Service Commission Staff's proposed modified net metering rules, filed in November 2017, utilities would be required to incorporate DG into their integrated resource plans. Specifically, utilities would be required to document the current level of DG in their service territories, discuss and analyze the impact that DG is having on the system resource requirements, and forecast future DG for at least a five-year period. Utilities would be encouraged to provide analysis or documentation on the monetary value of the avoided energy and capacity benefits provided by DG historically and forecasted into the future. An open session was held in February 2018. The Commission Staff filed final proposed rules in January 2019, which retain most of the same provisions as the previous version of proposed rules.	Docket No. R-33929 Proposed Modified Rules
MA	Distribution System Planning	S. 2564 directs the state's electric distribution utilities to annually create a map showing areas of critical need for energy storage systems. The maps are to include areas of actual or forecasted overload on distribution circuits or at substations. The bill died at the end of the legislative session.	S. 2564 (D)

	Grid Modernization Planning, Non-Wires Alternatives	H. 1725 and S. 1875 require distribution utilities to submit grid modernization plans every five years. These plans must include an evaluation of locational benefits and costs of local energy resources on the system. The plan must also identify optimal locations for local energy resources over the next ten years, additional spending necessary to integrate cost-effective local energy resources, and any barriers to deployment of local energy resources. Furthermore, the plans must propose or identify location-based incentives and other ways to deploy cost-effective local energy resources, as well as cost-effective ways to coordinate existing programs, incentives, and tariffs to maximize locational benefits and minimize incremental costs of these resources. Finally, the utilities would also be required to develop publicly accessible hosting capacity maps that are continually updated. The Department of Public Utilities would be required to initiate a proceeding by January 31, 2018 to establish a procedure for creating and filing these plans. The proceeding would also establish metrics and performance incentives to evaluate the distribution utilities' progress toward developing a system where local energy resources can be utilized to meet demand. The bill also creates a Grid Modernization Consumer Board to review utilities' grid modernization plans and budgets. The bills also require utilities to receive a "Determination of Wires" prior to constructing (or receiving a construction permit for) a transmission line, distribution line, or ancillary structure integral to the operation of a transmission or distribution line. As part of the application for this determination, the utility must describe alternatives to the facility and also include an investigation from an independent 3rd party of the ability for local energy resource alternatives to address or defer part or all of the wires investment. The investigation must include the total costs and benefits to ratepayers of both the wires project and the local alternatives. A Grid Modernization Consumer Board would be created by the bill, and this entity would be responsible for approving a Determination of Wires. The Board would be required to first consider whether any local energy resource alternatives, alone or in combination, could meet or defer the wires investment. The bills died at the end of the legislative session.	H. 1725 (D) S. 1875 (D)
ME	Non-Wires Alternatives	In April 2016, the Public Utilities Commission (PUC) opened an investigation into the designation of a Non-Transmission Alternative (NTA) Coordinator, and a final order was published in December 2017. The Commission found that the state's distribution utilities, Central Maine Power and Emera Maine, have the	Docket No. 2018-00171 Docket No. 2016-00049

best knowledge of the system, as well as the technical and engineering knowledge necessary to perform the role of the NTA Coordinator. However, the PUC noted that incentives in existing ratemaking encourage the utilities to invest in wires solutions over non-wires alternatives. Therefore, the PUC directed the utilities to file, within six months, proposals to address this incentive so that wires and non-wires solutions are on an equal footing from a ratemaking perspective.

In June 2018, the utilities filed their NTA report, which recommends (1) the establishment of a revenue decoupling mechanism for Emera, (2) the establishment of ratemaking approaches that treat situations expenditures related to non-wires alternatives (NWA) similar to traditional transmission and distribution investments, (3) incentives for the utilities to plan for and deploy NWA, (4) the establishment of a process to review utility NWA plans similar to utility transmission projects, (5) ratemaking tools for timely recovery of NWA costs, and (6) an approach to address innovative and cost-effective grid modernization projects, including pilots and demonstration projects, to develop ways of increasing efficiency and supporting future NWA projects. An initial case conference was held in July 2018, and the utilities filed a supplemental NTA report in early October.

The PUC Staff filed a bench memorandum with its proposed ratemaking and process alternatives in December 2018. The Staff recommended that for Emera, a revenue decoupling mechanism be considered as part of a more comprehensive rate review and that different ratemaking approaches be taken for transmission-level NWAs and distribution-level NWAs. For transmission NWAs, costs would be recovered through an annual rate adjustment and investments/capitalized expenses could earn a return at the utility's FERC-authorized rate of return. Any costs not allowed in FERC-jurisdictional transmission rates could be recovered through the distribution rate adjustment. For distribution NWAs, costs would also be recovered through an annual rate adjustment, with the utility earning a return at the rate of return on rate base approved by the PUC. Transmission NWA costs would be allocated to all utility customers, while distribution NWA costs would be allocated only to customers taking service at distribution voltages. For third-party owned NWAs, expenses would be capitalized through a service agreement, lease, or contract, and any expenses not capitalized could be recovered in the distribution rate adjustment. The Staff proposed that any ratemaking incentive program be structured as a pilot program. The staff also

		proposed that the utilities provide additional detail on the internal processes for considering NWAs and that the utilities file annual reports that detail capacity and load by circuit and identify all growth-related investments for the next three years. The Office of the Public Advocate also filed recommendations in December, recommending that the Commission reject the utilities' proposal, that the utilities file a complete financial model with earnings and ratepayer savings under different shared savings mechanisms, that a shared savings mechanism with 30% savings retained by utilities be approved, that capitalization of NWA expenses be approved, that utilities only be allowed to recover NWA incentives once capacity benchmarks are reached, and only allow recovery of capitalized NWA assets beginning at the time of the next rate case, but allow recovery of NWA expenses on a current basis.. Technical and case conferences are scheduled for January 2019.	
	Non-Wires Alternatives	In August 2018, the Office of the Public Advocate (OPA) filed a petition requesting that the Commission amend its "safe harbor" rules for local transmission planning. Under current rules, stakeholders are not permitted to bring forward evidence or cost-benefit studies to demonstrate why different planning assumptions should be used. The OPA suggests that allowing this intervention will help in the selection of reliability solutions that best suit customer needs. Comments were filed in September, October, and November.	Docket No. 2011-00494
MI	Distribution System Planning, Non-Wires Alternatives	In April 2018, the Michigan Public Service Commission (PSC) opened this docket for DTE Electric Company and Consumers Energy Company to file their five-year distribution investment and maintenance plans. Both utilities submitted their plans in April 2018, after which comments on the plans were accepted. A technical conference to discuss stakeholder concerns on the plans was held in August 2018. In September 2018, the PSC Staff filed a report providing a framework for future distribution plans. The report contained several recommendations, including that the PSC require a dynamic approach to load forecasting, that utilities be required to provide publicly available hosting capacity information, that utilities using AMI use standards developed by the Green Button Alliance to provide customers access to usage data, that future plans provide criteria for and information on non-wires alternatives projects, and that a common cost-benefit methodology be developed for use in future distribution plans. In November 2018, the PSC issued an order requiring the utilities to file their next round of distribution plans by mid-2020. The PSC order does not implement all	Docket No. U-20147 Michigan Distribution Planning Framework November 2018 Order

		of the Staff report's recommendations; the order does not require a dynamic approach to load forecasting, does not require hosting capacity studies to be performed, and does not require use of Green Button. The order does call for a technical conference to develop a common cost-benefit methodology and for a discussion on criteria for non-wires alternatives analyses. Environmental parties filed joint comments on Indiana Michigan Power's distribution plan on December 21, 2018.	
	Microgrid Rules	H.B. 5862, introduced in April 2018, establishes a statutory definition for microgrids, defining a microgrid as "a group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that acts as a single controllable entity with respect to the macrogrid and that connects and disconnects from the macrogrid to enable it to operate in grid-connected or island mode," with island mode meaning that power is not exchanged with the utility-owned transmission and distribution network. The bill did not advance out of committee during the 2018 legislative session.	H.B. 5862 (D)
	Microgrid Rules	H.B. 5865, introduced in April 2018, allows for the establishment of microgrids to support critical facilities (including hospitals, fire and police stations, and other facilities providing similar public services that need to be maintained in the event of a power supply interruption) by electric utilities or private entities. The bill would also require the Public Service Commission to prepare reports on distribution system reliability and the costs and benefits of microgrids. The bill did not advanced out of committee during the 2018 legislative session.	H.B. 5865 (D)
MISO	Wholesale Market Rules	In April 2017, DTE Electric submitted an Issue Submission Form to MISO requesting that tariffs for energy storage be updated. Current rules treat storage as a synchronous generator and do not recognize that storage acts as both a generator and a load, which results in sub-optimal use of the storage resource. This request references an ongoing review of this issue by FERC, prompted by an Indianapolis Power & Light request in 2016. MISO held Common Issue Meetings on energy storage in July and August 2017. At the August meeting, instructions were given to various MISO subcommittees to investigate storage integration issues. In December 2017, MISO released a charter for an Energy Storage Task Force, which will meet throughout 2018 to discuss issues surrounding the integration of energy storage. Meetings were held throughout the first three quarters of 2018, with an additional meeting taking place on November 2, 2018. A revised charter was issued in	Energy Storage Resource Optimization Energy Storage Task Force Page Common Issue Meeting July 24 Common Issue Meeting August 24

		September 2018, which indicates the group will convene until June 2019.	
	Wholesale Market Rules	In response to FERC Order 841, issued in February 2018, the MISO Advisory Committee is holding proceedings on incorporating energy storage into wholesale markets. The Market Subcommittee, Planning Advisory Committee, Reliability Subcommittee, and Resource Adequacy Subcommittee are holding proceedings on implementing Order 841. MISO held a joint stakeholder meeting in October 2018 to present its plans to comply with Order 841. In December 2018, MISO filed tariffs with FERC in order to comply with Order 841. MISO is adopting a definition of "electric storage resource" based on the language of Order 841. Additionally, MISO filed tariff changes which will allow energy storage resources to participate in capacity, resource adequacy, energy and ancillary services, blackstart service, and reactive supply and voltage control markets; energy storage had previously been limited to energy and operating reserves markets in MISO. MISO will phase out its transitional SER-Type II participation model for energy storage in March 2020, after the new participation model comes into effect.	MISO Issue Tracker Order 841 Joint Meeting October 10, 2018 FERC Docket No. ER19-465
MN	Distribution System Planning	The Public Utilities Commission opened a new proceeding in April 2018 for the development of Xcel Energy's 2018 Integrated Distribution Plan (IDP). The Commission Staff created draft filing requirements for the IDP, which were discussed in an April meeting. The proposed requirements direct utilities to file plans addressing: (1) long-term distribution system modifications and investments, (2) considerations used in related planning processes, and (3) long-term distribution system future outlooks. The Commission issued an order in August 2018 approving the IDP filing requirements. Xcel must file its IDP with the Commission annually beginning November 1, 2018. Xcel filed its IDP in November 2018, and the Commission opened a comment period on the plan.	Docket No. 18-251 Order
	Distribution System Planning	The Public Utilities Commission opened a new proceeding in April 2018 for the development of Ottertail Power's 2018 Integrated Distribution Plan (IDP). The Commission Staff created draft filing requirements for the IDP, which were discussed in an April meeting. The proposed requirements direct utilities to file plans addressing: (1) long-term distribution system modifications and investments, (2) considerations used in related planning processes, and (3) long-term distribution system future outlooks. The Commission opened a formal comment period in June 2018 and extended the deadline for comments	Docket No. 18-253

		and reply comments to the end of September 2018. During its December 2018 agenda meeting, the Commission considered whether or not to require Otter Tail to file an IDP by November 1, 2019.	
	Distribution System Planning	The Public Utilities Commission opened a new proceeding in April 2018 for the development of Minnesota Power's 2018 Integrated Distribution Plan (IDP). The Commission Staff created draft filing requirements for the IDP, which were discussed in an April meeting. The proposed requirements direct utilities to file plans addressing: (1) long-term distribution system modifications and investments, (2) considerations used in related planning processes, and (3) long-term distribution system future outlooks. The Commission opened a formal comment period in June 2018 and extended the deadline for comments and reply comments to the end of September 2018. During its December 2018 agenda meeting the Commission considered whether or not to require Minnesota Power to file an IDP by November 1, 2019.	Docket No. 18-254
	Distribution System Planning	In November 2018, Xcel Energy filed its hosting capacity report. Comments on the report will be accepted through February 2019.	Docket No. 18-684
	Integrated Resource Planning	Every two years, or as determined by the Commission, nine utilities file an IRP covering the next 15-year planning period. A demand response stakeholder workgroup was formed in late 2017 in light of a requirement for Xcel Energy to increase its demand response resources by 400 MW by 2023. The group met several times throughout 2018, including twice in August. Stakeholder meetings on the evolving electric system were also held in August 2018. In October 2018, Xcel filed a request to extend the deadline to file its 2020-2034 Upper Midwest IRP from February 1, 2019 to July 1, 2019. The Commission hosted a meeting in early December to consider Xcel's request. On December 14, 2018, Xcel hosted a workshop on demand-side management and battery storage.	Docket No. 15-21
MO	Distribution System Planning	In March 2017, the Missouri Public Service Commission (PSC) staff requested that the Commission open a workshop docket to gather information related the PSC's role in shaping the solar landscape. The proceeding is also intended to examine issues surrounding modified rate design proposals, AMI, property assessed clean energy financing, and the electric vehicle market. As part of the proceeding, the PSC Staff released a report on DERs in early April 2018. The report does not specifically recommend that a value of solar study be conducted, but did find that studies conducted in other	Docket No. EW-2017-0245 June 2018 Draft Rule

		states may not be fully informative for Missouri. Rather than recommending a full value study, Staff recommended that stakeholders focus on incorporating DERs into distribution system planning, as this may help provide a framework for DER valuation. In May 2018, PSC Staff published a draft rule for comment, and in late May 2018 a workshop was held to discuss the draft rule. In late June 2018, the PSC Staff filed an updated version of the draft rule for comment. The current version of the draft rule requires utilities to maintain a database of current DERs on their grids, assess the market potential for DERs as part of their triennial compliance filings, and evaluate DERs as part of the resource planning process, including integration with the transmission and distribution system. Several parties filed comments on the draft rule in July 2018. The Office of the Public Counsel argued against the need for the new rules, stating that current rules are sufficient and arguing that the database would be created too late to help inform current policy deliberations. The Division of Energy from the Missouri Department of Economic Development and Renew Missouri generally supported the draft rules, and made suggestions to include additional elements in the required analyses. The comments jointly submitted by utility parties suggested using a different definition for cost-effectiveness (the draft rules use a definition from the National Efficiency Screening Project, while the utilities suggest using the definition from the Missouri Energy Efficiency Investment Act of 2009) and suggest providing information on current DERs on the grid through annual filings rather than an online database. Action in this docket during the second half of 2018 focused on standard offer rules under PURPA; no further action was taken on the DER or AMI issues.	
MS	Integrated Resource Planning	In May 2018, the Public Service Commission opened a proceeding to consider the development of IRP rules. Parties filed initial comments in August 2018. In December 2018, the Commission issued a request for comments on Entergy Mississippi's proposed IRP rule, which it submitted with its initial comments. The proposed rules would require the consideration of utility-owned or controlled DERs and enabling technologies, such as broadband access, and data. The rules reference energy storage in the Demand Response and Energy Efficiency section. Comments are due within 45 days of the date of the order (order was issued December 11th).	Docket No. 2018-AD-64
NH	Non-Wires Alternatives	As part of the New Hampshire Public Utilities Commission's (PUC) June 2017 net metering successor tariff decision, the PUC ordered the	Docket No. DE 16-576

		implementation of four pilot programs, including a non-wires alternatives (NWA) pilot. The pilot would be focused on the installation of DG in lieu of distribution system upgrades. In April 2018, the PUC issued an order addressing the NWA pilot program, suspending the development of any DG-only NWA programs and deferring consideration of unrestricted NWA implementation to a grid modernization or integrated resource planning context. Instead, the PUC ordered that a distribution-level locational DG value study be undertaken instead, with a proposed scope and timeline to be filed within 3 months. The deadline for this scope was later extended, and in late November 2018, the Commission Staff filed a report with a proposed scope and timeline for the distribution-level locational DG valuation study. The proposed study scope covers only technologies eligible for net metering and will examine the value of avoided or deferred distribution investment costs resulting from elimination of capacity constraints. The study is expected to begin in Q2 2019 and be completed by the end of 2019. A public comment hearing on the proposed study scope was held in early January 2019. In January 2019, the PUC issued an order adopting an exception to the prohibition on voluntary tariff switching for net-metered customers wishing to participate in Liberty Utilities' new battery storage pilot.	Order No. 26,029 Order No. 26,124 Locational Value of Distributed Generation Study Scope Proposal
NJ	Distribution System Planning, Non-Wires Alternatives	A.B. 4525, introduced in 2018, directs the Board of Public Utilities to develop rules for the procurement of energy storage systems as part of the transmission and distribution planning process.	A.B. 4525 (I)
NV	Distribution System Planning	S.B. 146, enacted in June 2017, requires NV Energy to submit a Distributed Resources Plan to the Public Utilities Commission of Nevada (PUCN) by April 1, 2019 as an addendum to its integrated resource plan. The plan must (1) evaluate the locational benefits and costs of DERs, (2) propose standard tariffs for the deployment of cost-effective DERs, (3) propose cost-effective methods of coordinating existing programs to maximize the locational benefits of DERs, (4) identify additional spending necessary to integrate distributed resources into distribution planning, and (5) identify barriers to the deployment of DERs. The PUCN opened an investigation and rulemaking docket in July 2017 to implement S.B. 146. The PUCN released draft temporary regulations in July 2018, which it later approved through an October 2018 order. The temporary regulations establish the filing, content, approval, and updating process for Distributed Resources Plans.	S.B. 146 (2017) Docket No. 17-08022 NV Energy Proposed Regulations Temporary Regulations

	Integrated Resource Planning	S.B. 65, enacted in June 2017, makes three changes to NV Energy's resource planning process. First, NV Energy must meet with personnel from the Commission and the Bureau of Consumer Protection in the Office of the Attorney General at least four months before filing a resource plan, and provide them with an overview of the plan. In considering resource plans, the bill requires the Public Utilities Commission of Nevada (PUCN) to give preference to measures and sources of supply that provide the greatest economic and environmental benefits to the state, among other characteristics. Lastly, the bill requires the PUCN to include its justification for the preferences given to any resources. The PUCN opened a rulemaking docket in July 2017 to implement these changes and accepted comments through mid-October 2017. In March 2018, proposed regulations were sent to the Legislative Counsel Bureau (LCB) for review. The LCB submitted revised regulations in May 2018. The Commission held a public workshop and a hearing in July to solicit comments on the proposed regulations. An August 2018 order adopted the revised regulations. The regulation was filed with the Secretary of State in December 2018.	S.B. 65 (2017) Docket No. 17-07020 LCB Revised Regulations Order (August 2018)
NY	Distribution System Planning, Non-Wires Alternatives	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. In December 2018, the Public Service Commission (PSC) adopted an energy storage target and roadmap for deploying 1,500 MW of storage by 2025 and 2,000 MW by 2030. As part of the roadmap, the PSC directed the utilities to compile an inventory of unused, suitable land for non-wires alternatives, as well as interconnection upgrade costs for non-wires alternatives that can be included in RFPs. The Commission also directed the utilities to work with NYSERDA to develop a pilot DER data platform including anonymized customer and system data for DER developers.	Docket No. 18-00516/18-E-0130 NYSERDA Website
	Grid Modernization Planning	The "New York Grid Modernization Act" (A.B. 7480) requires utilities to develop smart grid deployment plans if, following a study, it is determined that smart grid deployment is in the public interest. The program is to include many components, including transmission and distribution system improvements, low-income assistance and education, access to real-time pricing data, AMI opt-out, opportunities for the use of smart appliance and plug-in or hybrid vehicles. The bill died at the end of the legislative session.	A.B. 7480 (D)

	Grid Modernization Planning	A.B. 4223 requires utilities to develop and adopt smart grid system deployment plans by July 2018 and issue RFPs by October 2018. The smart grid would allow for a two-way communications system with real time monitoring, diagnostics, and control. Utilities would be allowed recovery of their costs. The bill died at the end of the legislative session.	A.B. 4223 (D)
NYISO	Wholesale Market Rules	In December 2018, New York ISO (NYISO) filed revisions to its tariffs and market rules to facilitate participation of energy storage resources, in compliance with FERC Order 841. FERC Order 841 directed ISOs and RTOs to revise their rules to allow energy storage resources to participate in wholesale energy, capacity, and ancillary markets. NYISO offers four modes for energy storage: (1) ISO Committed Fixed (2) ISO Committed Flexible, (3) Self Committed Fixed, and (4) Self Committed Flexible. Under ISO Committed, the ISO would determine optimal dispatch time. Under ISO Committed Flexible, the storage system would be dispatched in the real time market based on LMP. Under the Self Committed options, the suppliers would decide the time for dispatch. Energy storage systems are required to continuously supply energy for four hours in NYISO. NYISO tariffs apply only to wholesale resources; behind-the-meter resources must be sub-metered and dual participation in utility programs and NYISO markets is not allowed. FERC allowed a 21-day comment period on the revised proposed rules. Several stakeholders requested that FERC to extend the comment period to 45 days, as the proposal includes a significant amount of filings to review. The final rules are required to be implemented by December 3, 2019 to comply with FERC Order 841. NYISO has requested an implementation extension to May 1, 2020 as it is currently under updating its market software.	FERC Docket No. ER19-467
PJM	Wholesale Market Rules	In April 2017, the Energy Storage Association (ESA) filed a complaint against PJM before the Federal Energy Regulatory Commission (FERC), alleging that PJM unilaterally changed its frequency regulation market, discriminating against existing energy storage resources. The PJM frequency regulation market is categorized into RegA (for traditional resources with limited ramp rates) and RegD (for resources with short ramp rates, including batteries). Previously, the RegD resources were energy neutral. However, in January 2017 PJM changed its rules that maintained energy neutrality and eliminated the provision for RegD resource use for short durations. The FERC issued a decision in March 2018, partially granting ESA's requests, ruling that parameters for PJM's regulation market signals must be included in the PJM tariff and are subject to FERC review. The decision	FERC Docket No. EL17-64 FERC Complaint

		also instructs FERC staff to set up a technical conference on other issues arising from this matter. In May 2018, the parties requested and FERC approved appointment of a settlement judge and postponement of the technical conference. Settlement conferences took place throughout the third quarter of 2018 and continued through the fourth quarter of 2018 and into 2019; the ALJ presiding over the case indicated that the parties have reached an agreement in principle.	
	Wholesale Market Rules	In December 2018, PJM filed its compliance plan to update its tariffs and market rules to facilitate the participation of energy storage resources in its markets, in compliance with FERC Order 841. FERC Order 841 directed ISOs and RTOs to revise their market rules to integrate energy storage into wholesale energy, capacity, and ancillary markets. Energy storage systems are required to continuously supply energy for ten hours in PJM. PJM categorizes energy storage into three modes: (1) continuous, (2) charge, and (3) discharge. In continuous mode, resource can both charge or discharge with no limitation on start up or ramp rate. PJM would require all storage resources not owned by utilities only to sell back to PJM, and not sell to others or use stored power themselves. FERC allowed a 21-day comment period on the revised rules. Several stakeholders requested that FERC to extend the comment period to 45 days, as the proposal includes a significant amount of filings to review. The final rules are required to be implemented by December 3, 2019 to comply with FERC Order 841.	FERC Docket No. ER19-469
RI	Distribution System Planning, Non-Wires Alternatives	In October 2018, National Grid filed its 2019 System Reliability Procurement (SRP) Report. National Grid proposed efforts to develop and promote the Rhode Island System Data Portal. The Portal includes company reports on distribution system planning, an overview of distribution assets, a heat map of distribution feeder load, and a hosting capacity map. As part of the SRP report, National Grid proposed (1) identifying locations where electric vehicle fast charging stations could be installed by September 2019, (2) identifying areas where large non-electric public transportation fleets are located to forecast potential fleet conversion to electric vehicles by July 2019, and (3) including redacted area studies by the end of 2019. The SRP report also includes a proposal to reissue an RFP for a non-wires alternative (NWA) opportunity in Tiverton and Little Compton. A battery storage project was previously selected for this NWA opportunity, but the project was not able to be completed. The report identifies additional NWA opportunities and proposes that RFPs be issued for these as well. A hearing was held on December 10th.	Docket No. 4889 2019 System Reliability Procurement Report

SPP	Wholesale Market Rules	In December 2018, the Southwest Power Pool filed its FERC Order 841 compliance plan. The plan would allow storage resources to register as a "market storage resource" and provide energy, regulation-up, regulation-down, spinning reserve, and supplemental reserve services.	FERC Order No. ER19-460
TX	Non-Wires Alternatives	In February 2018, the Texas Public Utility Commission (PUC) opened this docket to address the use of non-traditional technologies for electric delivery service. This docket arises from a previous docket, No. 46368, which concerned AEP Texas North Company's request to deploy energy storage as a non-wires alternative. The earlier docket has been closed to allow for this wider investigation. In early October 2018, the PUC issued a request for comments on a set of questions pertaining to non-traditional electric delivery technologies. The questions address several issues, including whether and how transmission and distribution utilities could use non-traditional technologies (including energy storage) to improve reliability on their systems; whether there is legal authority for them to do so; what steps regulators should take to approve, track, and manage these non-traditional technologies; and what effects these non-traditional technologies could have on the ERCOT market. Comments were filed throughout November 2018.	Docket No. 48023 Docket No. 46368
	Resource Planning	In September 2018, the Public Utility Commission (PUC) opened a docket to amend a rule (16 TAC 25.505) dealing with resource adequacy in the ERCOT region. The rule currently prescribes several measures, including reporting requirements for utilities, publications on resource adequacy to be prepared by ERCOT, and a scarcity pricing mechanism. On December 13, 2018, the PUC proposed several changes to the rule and set an open meeting for December 20, 2018. The proposed changes include a change to the gas price index, changes to the scarcity pricing mechanism, and updated reporting requirements. The PUC approved the rule proposal at the December 20, 2018 meeting and proposed publication of the amendments on January 3, 2019.	Docket No. 48721 16 TAC 25.505
WA	Distribution System Planning	In May 2015, the Washington Utilities and Transportation Commission staff initiated a proceeding (UE-151069) to investigate the role of energy storage in utility planning and procurement. The Commission later initiated a rulemaking proceeding in September 2016 (U-161024) to consider changes to the integrated resource planning (IRP) process. The two proceedings overlap in certain areas. The Commission specifically seeks to evaluate	Docket No. UE-151069 Docket No. U-161024 Final Policy Statement

how recent advances in the energy industry, such as the growth of DG and development of energy storage technologies, should be treated in the IRP. In October 2017, the Commission issued its final Report and Policy Statement on Treatment of Energy Storage Technologies in IRP and Resource Acquisition. The report cites energy storage as a key enabling technology for utilities to comply with state energy policies, and that utilities should be diligently working to identify and pursue cost-effective energy storage opportunities. The report specifically discusses three policy principles related to energy storage: (1) changing planning paradigms, (2) providing modeling guidelines, and (3) identifying principles for regulatory treatment of energy storage investments. In January 2018, the Commission submitted its Report on Current Practices in Distributed Energy Resource Planning. The report includes a survey of how other states conduct DER planning, a survey of the current practices of Washington utilities, and ten recommendations for improving the planning process.

In April 2018, the Commission filed draft rules for distributed system planning in Docket No. U-161024. The draft rules require utilities to form a separate advisory group to assist the utilities in developing their distribution system plans, in addition to the usual IRP advisory group. According to the draft rules, distribution system plans must include a short term plan identifying planned capital investments, a long term plan identifying how the utility is improving distribution system operations and transparency, and a report identifying potential tools and practices to facilitate the integration of DERs. A number of parties filed comments on the draft rules during Q2 and Q3 2018, and a workshop was held in October 2018.

In December 2018, the Commission released draft rules for utility RFPs. The draft rules include language promoting the use of technology-neutral RFPs and requiring RFPs to identify utility-owned transmission assets that are available to be used by bidders to assist in meeting the resource need. The rules also require the use of an independent evaluator under certain conditions, such as when the utility or an affiliate is allowed to submit a bid. The Commission is accepting comments on the draft RFP rules until January 31, 2019.

Final Report

Distribution Planning Draft Rules

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of late January 2019.

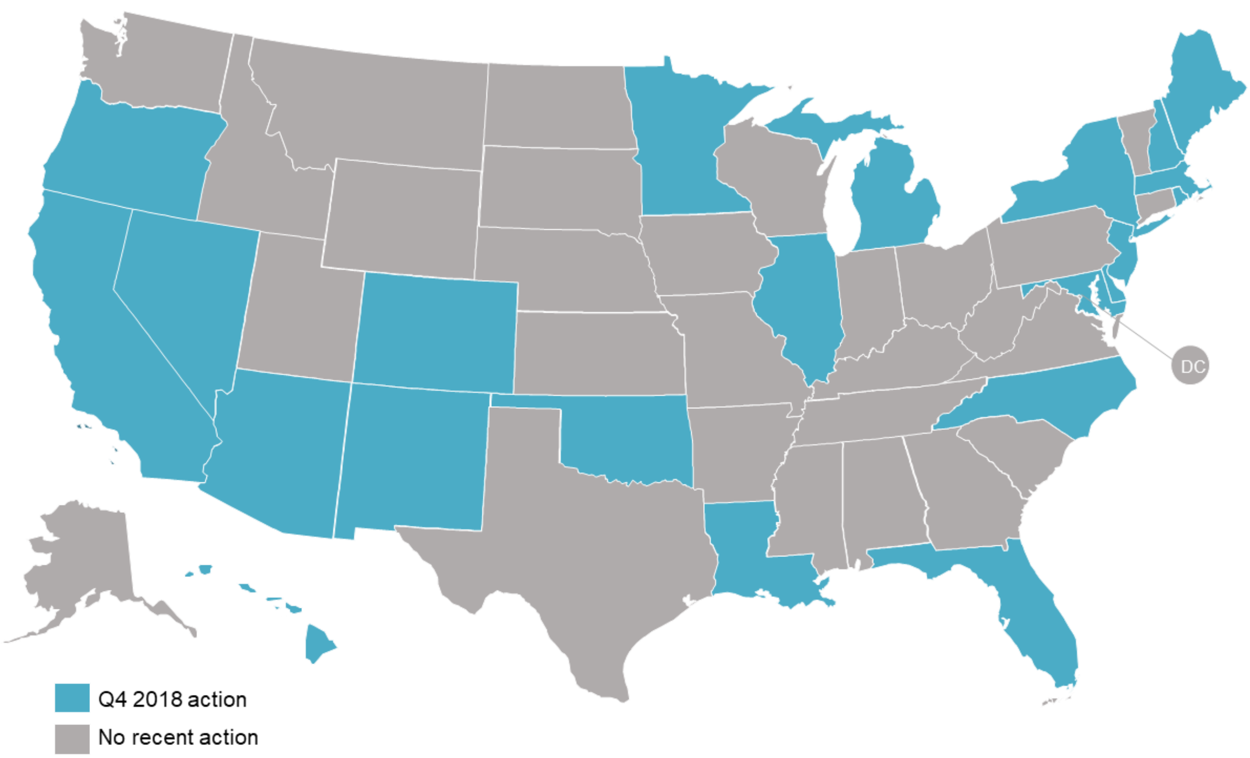
UTILITY BUSINESS MODEL AND RATE REFORMS

Key Takeaways:

- In Q4 2018, 22 states took 43 actions to reform rate designs, regulatory structures, or utility business models.
- Eleven states and DC took action on rate design reforms, while 17 states considered utility business model or ratemaking reforms.
- National Grid in Massachusetts proposed performance incentive mechanisms in Q4 2018, while the California Public Utilities Commission opened a proceeding related to real-time pricing and demand charges.

In Q4 2018, 22 states plus DC took action related to utility business model and rate reforms. Of these, 11 states plus DC considered rate design changes, while 17 states considered utility business model or ratemaking adjustments. The most common types of reforms considered were related to performance-based regulation and time-varying rates.

Figure 31. Action on Utility Business Model and Rate Reform (Q4 2018)



The Arizona Corporation Commission opened a new proceeding on retail electric competition in December 2018, following a workshop discussion on this issue. The new proceeding will consider market structure, transmission planning, reliability, community choice aggregation, legal impacts, and other unintended consequences. Action related to market competition was also taken in Florida, where a group is collecting signatures to get a Constitutional amendment on the 2020 ballot that would make the state's wholesale and retail markets fully competitive. Nevada citizens voted down a ballot initiative to deregulate the state's electric utility industry in November 2018.

Many states continue to make progress toward implementing performance-based rate structures, with National Grid in Massachusetts filing a proposal to replace its capital investment recovery mechanism with a performance-based ratemaking plan. National Grid requested approval for performance incentives based on peak reduction, electric vehicle adoption, electric vehicle supply equipment cost containment, and customer ease.

Figure 32. Action on Rate Design and Utility Business Models (Q4 2018)

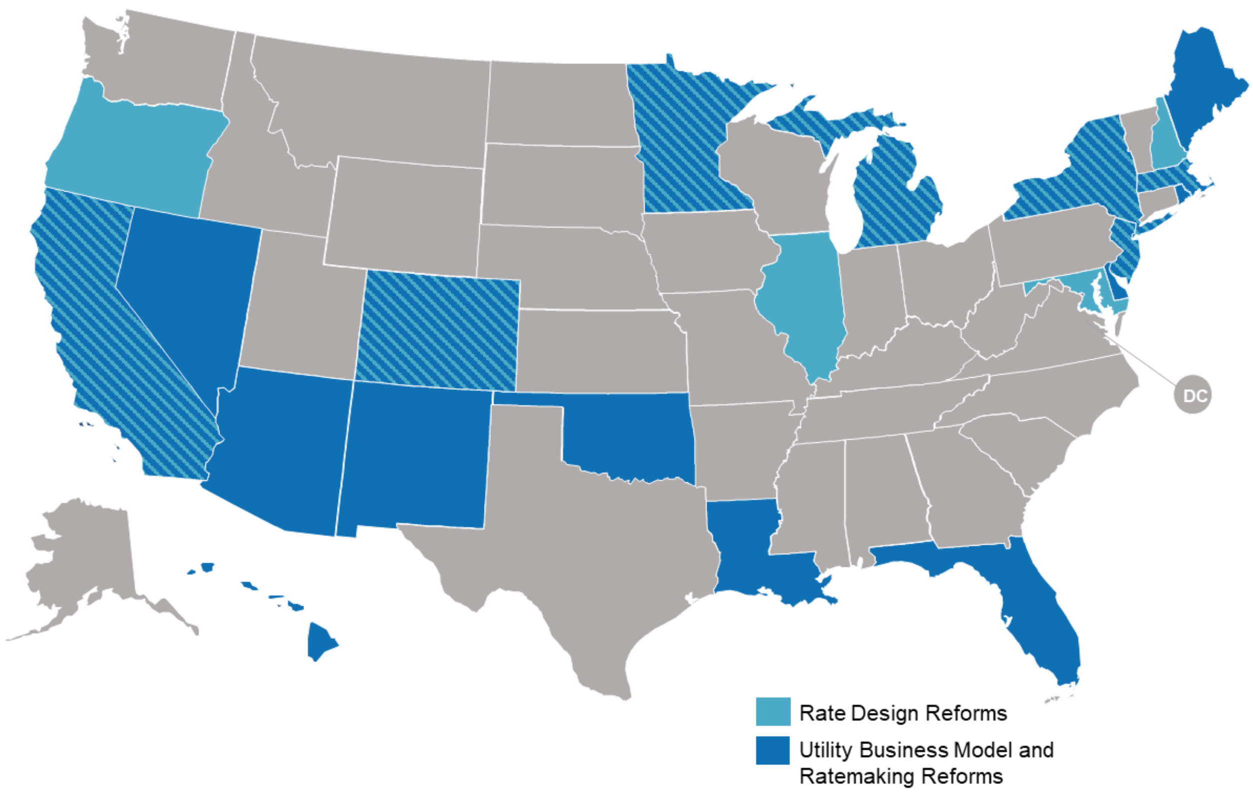


EXHIBIT 4

Table 12. Updates on Utility Business Model and Rate Reform (Q4 2018)

State	Sub-Topic	Description	Source
AZ	Utility Business Model Reform	In Arizona the Commission opened a new docket in December 2018 following a workshop discussion on retail electric competition. The new proceeding will discuss retail electric competition including market structure, transmission planning, reliability, community choice aggregation, legal impacts, and other unintended consequences.	Docket No. RE-00000A-18-0405
CA	Demand Charges, Time-Varying Rates	In November 2018, the California Solar and Storage Association, California Energy Storage Association, Enel X, ENGIE Services, ENGIE Storage, OhmConnect, Solar Energy Industries Association, and Stem filed a petition for the California Public Utilities Commission (CPUC) to open a rulemaking to (1) consider whether to require the state's three large IOUs to offer real-time pricing tariffs to all customer classes whether the utilities should be required to offer less complex dynamic rates for the residential and small commercial classes and (2) consider two demand charge reforms for non-residential customers. Specifically, the groups are requesting that the CPUC prohibit non-coincident peak demand charges and consider alternatives to a single monthly coincident peak demand measurement, such as daily coincident peak demand charges or charges based on averaged demand.	Docket No. P-18-11-004
	Time-Varying Rates	Pacific Gas and Electric (PG&E) filed its proposed TOU rates in December 2017. PG&E's proposal includes a default TOU rate with a 3-hour peak period, and three optional rates for customers who opt out of the default. The proposal also includes a limited roll-out set for November 1, 2019, but PG&E states that it would prefer a roll-out of October 1, 2020 to allow more time for marketing and other transitional actions. The California Public Utilities Commission issued a scoping ruling in March 2018 and an amended scoping ruling in April 2018. The two rulings establish the scope of issues that will be discussed across three phases and the schedule for the remainder of the proceeding. Phase I will resolve questions related to the proposed start dates for the default TOU rates. Phase II will consider the utility's specific TOU rates, and Phase III will consider the utility's proposals for fixed charges and/or minimum bills. A May 2018 decision established that PG&E will begin transitioning eligible customers to default TOU rates in October 2020. The California Solar and Storage Association filed a motion in June 2018 to clarify that the scope of the proceeding includes a consideration of alternative, non-dynamic rate designs. A July ruling affirmed that alternative, non-	Docket No. A-17-12-011 Decision No. 18-05-011

	dynamic rate designs are within the scope of the proceeding. A proposed decision filed in November 2018 approves SDG&E's proposed rates, but defers a decision on PG&E's rates, since they will have a later rollout. The proposed decision does, however, approve proposals by PG&E and SCE to implement a line item discount for CARE customers. On December 13, 2018, the Commission issued a decision largely adopting the proposed decision, with the addition that virtual net metering and net metering aggregation customers will not be included in the transition to default TOU rates due to issues with rate comparison calculation for these customers.	
Time-Varying Rates	San Diego Gas and Electric (SDG&E) filed its proposed TOU rates in December 2017. SDG&E's proposal includes a default 3-period tiered TOU rate. Customers who wish to opt out of the default rate can choose between a simpler 2-period TOU rate or a tiered non-TOU rate. SDG&E's proposal includes a transition to default TOU rates on January 1, 2019. The California Public Utilities Commission issued a scoping ruling in March 2018 and an amended scoping ruling in April 2018. The two rulings establish the scope of issues that will be discussed across three phases and the schedule for the remainder of the proceeding. Phase I will resolve questions related to the proposed start dates for the default TOU rates. Phase II will consider the utility's specific TOU rates, and Phase III will consider the utility's proposals for fixed charges and/or minimum bills. A May 2018 decision established that SDG&E will begin transitioning eligible customers to default TOU rates in March 2019. The California Solar and Storage Association filed a motion in June 2018 to clarify that the scope of the proceeding includes a consideration of alternative, non-dynamic rate designs. A July ruling affirmed that alternative, non-dynamic rate designs are within the scope of the proceeding. A proposed decision filed in November 2018 approves SDG&E's proposed rates, but defers a decision on PG&E's rates, since they will have a later rollout. The proposed decision does, however, approve proposals by PG&E and SCE to implement a line item discount for CARE customers. On December 13, 2018, the Commission issued a decision largely adopting the proposed decision, with the addition that virtual net metering and net metering aggregation customers will not be included in the transition to default TOU rates due to issues with rate comparison calculation for these customers.	Docket No. A-17-12-013 Decision No. 18-05-011
Time-Varying Rates	Southern California Edison (SCE) filed its proposed default TOU rates in December 2017. SCE is seeking approval of two default "TOU Light" rates, which use	Docket No. A-17-12-012

	slightly different peak periods and feature seasonally-differentiated tiers. Both rates were previously approved for SCE's Default TOU Pilot, which is expected to roll out in March 2018. SCE will select the lowest cost rate when implementing its default TOU rate beginning in October 2020 and concluding 15 months later. The California Public Utilities Commission issued a scoping ruling in March 2018 and an amended scoping ruling in April 2018. The two rulings establish the scope of issues that will be discussed across three phases and the schedule for the remainder of the proceeding. Phase I will resolve questions related to the proposed start dates for the default TOU rates. Phase II will consider the utility's specific TOU rates, and Phase III will consider the utility's proposals for fixed charges and/or minimum bills. A May 2018 decision established that SCE will begin transitioning eligible customers to default TOU rates in October 2020. The California Solar and Storage Association filed a motion in June 2018 to clarify that the scope of the proceeding includes a consideration of alternative, non-dynamic rate designs. A July ruling affirmed that alternative, non-dynamic rate designs are within the scope of the proceeding. A proposed decision filed in November 2018 approves SDG&E's proposed rates, but defers a decision on PG&E's rates, since they will have a later rollout. The proposed decision does, however, approve proposals by PG&E and SCE to implement a line item discount for CARE customers. On December 13, 2018, the Commission issued a decision largely adopting the proposed decision, with the addition that virtual net metering and net metering aggregation customers will not be included in the transition to default TOU rates due to issues with rate comparison calculation for these customers.	Decision No. 18-05-011
Time-Varying Rates	A.B. 2569, introduced in February 2018, prohibits the California Public Utilities Commission from approving default TOU rates for residential customers in hot climate zones who are projected to experience bill increases of 20% or more in at least two summer months. The bill did not advance during the 2018 legislative session.	A.B. 2569 (D)
Utility Business Model Reform	An ongoing proceeding in California is investigating DER integration methods. The scope of the proceeding includes: (1) the development of a competitive solicitation framework for DERs, (2) the continued development of technology-neutral cost-effectiveness methods and protocols, (3) leveraging the work performed in the Distribution Resource Plans proceeding (see Studies and Investigations), and (4) the role of the utilities, business models, and financial interests in DER deployment. A December	Docket No. R-14-10-003 Decision No. 18-06-010

		2016 decision established a Competitive Solicitation Framework and a Utility Regulatory Incentive Pilot for the procurement of DERs that displace or defer the need for investments in traditional distribution infrastructure. The specific incentive adopted for the pilot was 4% pre-tax applied to the annual payment for the DER alternative to the traditional distribution investment. The decision required each utility to identify one DER project, with the option of identifying up to three additional projects to test the incentive mechanism. A June 2018 decision addressed cost-recovery for the Incentive Pilot program. In November 2018, San Diego Gas and Electric (SDG&E) filed an evaluation report on its Streamlined Competitive Solicitation Framework and Utility Regulatory Incentive Mechanism pilot. The report indicates that SDG&E launched its Pilot Request for Offers in January 2018 and did not receive any conforming bids that were cost effective. the report presents a series of recommendations for improving the process, and the Commission opened a comment period on the report.	
CO	Time-Varying Rates	As the result of a settlement agreement in Docket No. 16AL-0048E, Xcel Energy commenced two pilot residential TOU rate pilots. The pilots are being tracked and evaluated in Docket 17M-0204E. The Public Utilities Commission has held informational meetings in Q1 2018 in which information on pilot projects in other areas (including Sacramento, CA, and Fort Collins, CO) was presented. In May 2018, Xcel Energy filed various materials relating to its outreach and information process for the pilot program In July 2018, Commission Staff filed a marketing flyer form the City of Fort Collins to document the TOU rate that will go into effect for Fort Collins in October 2018.	Docket No. 17M-0204E Docket No. 16AL-0048E
DE	Ratemaking	Senate Substitute 1 for S.B. 80, signed in June 2018, allows utilities to apply a distribution system improvement charge (DISC), subject to the approval of the Commission. The bill identifies eligible distributed system improvements as new, used and useful electric utility plant projects that do not increase revenues by connecting the distribution system to new customers, are in service, and satisfy one of four additional criteria related to the equipment being replaced. The Commission opened a new proceeding in early October to develop regulations. The Staff presented proposed regulations in October, which the Commission adopted. Delmarva then filed a motion to modify a part of the regulation, which the Commission also accepted. Delmarva filed comments in November 2018 requesting additional changes to the regulations.	Reg. 64 Senate Sub 1 for S.B. 80 (E)

	Ratemaking	In November 2018, Delmarva Power & Light filed an application to implement a Distribution Service Improvement Charge (DSIC). The DSIC rate would be 0.29%. In December 2018, the Public Service Commission issued an order allowing the DSIC rate of 0.29% to go into effect starting January 1, 2019 on an interim basis, subject to audit and final approval. If it is found that the DSIC rate was improperly calculated through an audit, then Delmarva will be required to refund the appropriate amount.	Docket No. 18-1253
FL	Utility Business Model Reform	Florida Energy Choice is soliciting signatures for its petition to provide electricity choice in Florida. The petition proposed a constitutional amendment to make the state's wholesale and retail electricity markets fully competitive. If the petition receives enough signatures, it will be included on the 2020 ballot.	Florida Energy Choice Petition
HI	Utility Business Model Reform	The Public Utilities Commission opened a new proceeding in April 2018 to investigate the economic, technical, and policy issues associated with performance-based regulation for the HECO companies. The proceeding will be divided into two phases. Phase 1 will evaluate the current regulatory framework and identify which incentive mechanisms may not be functioning as intended, and to identify specific areas that should be targeted for improvement. In Phase 2, the Commission will work collaboratively with stakeholders to refine elements of the existing regulatory framework, develop incentive mechanisms to better address specific objectives, and explore alternative regulatory frameworks. The Commission held technical workshops in July and September 2018. The Commission Staff issued a concept paper in September 2018 to provide parties with a common understanding and suggested approach for assessing a revised set of potential regulatory outcomes, with respect to current regulatory mechanisms. The Commission staff released a third concept paper and hosted a third technical workshop in November 2018. Parties filed briefs on performance metrics in early January 2019.	Docket No. 2018-0088 Concept Paper #3
IL	Time-Varying Rates	In November 2018, Commonwealth Edison filed a residential TOU pricing pilot tariff. The tariff uses a three-part supply rate with "super peak," peak, and off-peak hours. The pilot will be available for four years. Commonwealth Edison also filed a request to revise its Integrated Distribution Company Implementation Plan to allow for the promotion, advertising, and marketing of the pilot program. A prehearing conference took place January 22, 2019.	Docket No. 18-1824

LA	Ratemaking	As part of Entergy New Orleans' general rate case filed in September 2018, the utility requested approval for a new cost recovery mechanism for its demand-side management (including demand response) initiatives. Entergy proposed a new rider, Rider DSMCR, to fund its Energy Smart programs for program year 10 and beyond. The proposed rider would include direct and indirect costs of the demand-side management offerings, lost contributions to fixed costs, and some type of an incentive. Entergy would earn a return on its demand-side management offerings, in order to put demand and supply resources on a more equal footing.	City Council Docket No. 18-07
MA	Demand Charges, Time-Varying Rates	S. 2564 requires the state's distribution utilities to offer residential and small commercial and industrial customers at least one TOU rate option. The rates are to include differentials for energy supply, transmission, and distribution, and are not to include demand charges. Peak periods are not to be longer than six hours per day, and once per year, the utilities are to provide customers with estimated bills under each of the available rate options. If opt-out TOU rates are considered, the impact on low-income customers and options to mitigate adverse impact is to also be considered. The bill died at the end of the 2017-2018 legislative session.	S. 2564 (D)
	Fixed Charges, Time-Varying Rates	H. 1725 and S. 1875 prohibit the Department of Public Utilities from approving residential fixed charges that are higher than the sum of connection costs, billing, and provision of customer service. The bills also require each distribution company to offer customers a time-of-use rate option. The company would also be required to provide a summary of available rate options with expected bill impacts for the customer once per year. Customers opting in to time-of-use rates for the first time would be offered bill protection for at least one year, where the customer would not be required to pay more than they would have paid under their previous rate schedule. The bills did not advance during the 2017-2018 legislative session.	H. 1725 (D) S. 1875 (D)
	Utility Business Model Reform	In Eversource's latest general rate case, filed in January 2017, the utility requested approval of a performance-based ratemaking (PBR) mechanism, whereby rates would be adjusted annually in accordance with a revenue-cap formula. The Department of Public Utilities (DPU) issued an order in November 2017 on the revenue requirement portion of the case, approving Eversource's proposed PBR mechanism, including an earnings sharing mechanism (25% to shareholders and 75% to ratepayers). The DPU ordered Eversource to submit	Docket No. 18-50 Docket No. 17-05 Order Establishing Eversource's Revenue Requirement

metrics and benchmarks for customer satisfaction/engagement and system peak demand reduction, as well as a climate adaptation plan to use in developing future metrics and benchmarks related to climate adaptation and greenhouse gas emissions reduction.

In March 2018, Eversource filed its proposed PBR metrics, which fall into three categories: improvements to customer service/engagement, reductions in system peak, and strategic planning for climate adaptation. Within the customer service category, Eversource proposed the following metrics: (1) overall customer satisfaction, (2) customer engagement (customer engagement platform, use of outage map, social media engagements, and digital engagement), (3) producer satisfaction (based on a satisfaction survey), and (4) producer engagement (based on the producer portal). For the peak reduction category, the utility will work to reduce system peak through company-controlled measures in energy efficiency, demand response, company-owned storage, company-owned solar, upgrading standard technology, volt/VAR optimization, and reduced line losses. Eversource notes that it will also produce an annual report on peak load reduction through time-varying rates and DG tracking. For the climate adaptation planning, Eversource plans to (1) deploy 7,000 low loss transformers over five years, (2) establish design leak rates for SF-6 containing equipment, (3) replace 45% of fleet diesel with biofuels, (4) transition 25% of facility square footage to LED or energy-efficient lighting by 2020, (5) install 62 MW of solar, (6) deploy a grid-connected storage project to displace the need for diesel generators, (7) study volt/VAR optimization efforts and associated emissions, (8) prioritize substations at flooding risk, (9) evaluate new equipment to improve performance in floods, (10) harden the overhead system, and (11) augment the outage prediction model to include the climate impacts of flooding.

In June 2018, the DPU opened a new docket for review of the proposed PBR metrics. The Attorney General's Office of Ratepayer Advocacy filed testimony in September 2018, finding that Eversource's proposed metrics "fail to identify, quantify, or ensure any measurable benefits to customers that can be attributed to a PBR form of rate regulation." An evidentiary hearing was held in late October 2018, and parties filed briefs in November 2018. Eversource filed an initial brief in early December 2018, discussing its proposed PBR metrics.

	Utility Business Model Reform	In November 2018, National Grid filed a general rate case, which includes a performance-based ratemaking (PBR) plan that would replace the capital investment recovery mechanism. National Grid proposed four performance incentive mechanisms: (1) peak reduction (measured by total incremental MW contributions from utility owned or influenced measures during the top five peak events of the summer for a maximum of three hours at a time), (2) electric vehicle adoption (measured by increased electric vehicle adoption in the utility's service territory above forecasted business as usual), (3) electric vehicle supply equipment cost containment (measured by cost-efficient delivery of charging ports in the proposed Phase II Electric Vehicle program), and (4) customer ease (measured by the "customer ease score" reflecting how easy it is for customers to interact and do business with the utility). National Grid also proposed three "scorecard metrics" which will not be tied to performance incentives, but will help make the utility's performance more transparent. These scorecard metrics are: (1) greenhouse gas emissions reduction, (2) customer engagement, and (3) DER customer experience. Public hearings are scheduled for March 2019.	Docket No. 18-150
MD	Time-Varying Rates	As part of Maryland's grid modernization proceeding (Public Conference No. 44), utilities are developing pilot programs for time-varying rates. In August 2017, the Rate Design Working Group submitted its report. The group noted that although the working group members agreed on discrete elements, the group was unable to reach consensus on the design of the pilot program. The report recommended a pilot program that tries to best reflect the different viewpoints discussed in the group. In November 2017, the Public Service Commission (PSC) published an order stating that the materials submitted by the rate design working group are not yet sufficiently specific to approve the TOU pilot programs. The PSC directed the working group leaders to continue convening the group to refine the pilot program designs. In February 2018, the working group filed its revised report with detailed descriptions of the proposed TOU pilots. The report identifies six decision points for the pilot programs to move forward. The Commission issued a letter order in May 2018, addressing each of the six decision points developed by the working group, and requesting that the utilities proceed with their rate design pilots. The utilities filed a joint implementation plan and updated budgets in late May 2018 and requested a modification to the pilot program development timeline, which would have the pilot rates begin no later than April 2019. The	Public Conference No. 44

		Commission approved the joint utilities' request in June 2018. The joint utilities filed their marketing and outreach plans in July 2018, and parties provided comments. In December 2018, the PSC directed the utilities to proceed with implementation of the TOU pilots.	
ME	Utility Business Model Reform	In April 2016, the Public Utilities Commission (PUC) opened an investigation into the designation of a Non-Transmission Alternative (NTA) Coordinator, and a final order was published in December 2017. The Commission found that the state's distribution utilities, Central Maine Power and Emera Maine, have the best knowledge of the system, as well as the technical and engineering knowledge necessary to perform the role of the NTA Coordinator. However, the PUC noted that incentives in existing ratemaking encourage the utilities to invest in wires solutions over non-wires alternatives. Therefore, the PUC directed the utilities to file, within six months, proposals to address this incentive so that wires and non-wires solutions are on an equal footing from a ratemaking perspective. In June 2018, the utilities filed their NTA report, which recommends (1) the establishment of a revenue decoupling mechanism for Emera, (2) the establishment of ratemaking approaches that treat situations expenditures related to non-wires alternatives (NWA) similar to traditional transmission and distribution investments, (3) incentives for the utilities to plan for and deploy NWA, (4) the establishment of a process to review utility NWA plans similar to utility transmission projects, (5) ratemaking tools for timely recovery of NWA costs, and (6) an approach to address innovative and cost-effective grid modernization projects, including pilots and demonstration projects, to develop ways of increasing efficiency and supporting future NWA projects. An initial case conference was held in July 2018, and the utilities filed a supplemental NTA report in early October. The PUC Staff filed a bench memorandum with its proposed ratemaking and process alternatives in December 2018. The Staff recommended that for Emera, a revenue decoupling mechanism be considered as part of a more comprehensive rate review and that different ratemaking approaches be taken for transmission-level NWAs and distribution-level NWAs. For transmission NWAs, costs would be recovered through an annual rate adjustment and investments/capitalized expenses could earn a return at the utility's FERC-authorized rate of return. Any costs not allowed in FERC-jurisdictional transmission	Docket No. 2018-00171 Docket No. 2016-00049

		rates could be recovered through the distribution rate adjustment. For distribution NWAs, costs would also be recovered through an annual rate adjustment, with the utility earning a return at the rate of return on rate base approved by the PUC. Transmission NWA costs would be allocated to all utility customers, while distribution NWA costs would be allocated only to customers taking service at distribution voltages. For third-party owned NWAs, expenses would be capitalized through a service agreement, lease, or contract, and any expenses not capitalized could be recovered in the distribution rate adjustment. The Staff proposed that any ratemaking incentive program be structured as a pilot program. The staff also proposed that the utilities provide additional detail on the internal processes for considering NWAs and that the utilities file annual reports that detail capacity and load by circuit and identify all growth-related investments for the next three years. The Office of the Public Advocate also filed recommendations in December, recommending that the Commission reject the utilities' proposal, that the utilities file a complete financial model with earnings and ratepayer savings under different shared savings mechanisms, that a shared savings mechanism with 30% savings retained by utilities be approved, that capitalization of NWA expenses be approved, that utilities only be allowed to recover NWA incentives once capacity benchmarks are reached, and only allow recovery of capitalized NWA assets beginning at the time of the next rate case, but allow recovery of NWA expenses on a current basis.. Technical and case conferences are scheduled for January 2019.	
MI	Time-Varying Rates	In an April 2018 order resolving a general rate case for DTE Electric that began in 2017, the Commission ordered DTE to begin moving to default TOU rates in its next rate case. In July 2018, DTE filed a new rate case that includes default TOU rates for residential customers. A hearing took place in December 2018, and a proposal for decision is expected in March 2019.	Docket No. U-20162 Docket No. U-18255
	Utility Business Model Reform	In May 2018, Consumers Energy filed a proposal for reconciliation of its demand response costs, including a financial incentive mechanism to encourage the use of demand response. The proposed incentive would allow the utility to earn 20% on all expenses associated with “building” and using demand response programs and resources. Initial testimony was due in January 2019, and a hearing is scheduled for February 27-28, 2019.	Docket No. U-20164
MN	Time-Varying Rates	In connection with its grid modernization plan, Xcel Energy filed a proposal for a pilot TOU tariff in	Docket No. 17-775

	November 2017. The pilot program would be rolled out in two communities of the Twin Cities metropolitan area through auto-enrollment with the opportunity for customers to opt out. The pilot tariff includes an on-peak period of 3PM to 8PM on weekdays, with prices set at a 4:1 ratio between on-peak and off-peak rates. The Commission held a meeting in May 2018 to discuss the proposal and issued an order in August approving the pilot program. The Office of the Attorney General – Residential Utilities and Antitrust Division submitted a petition for reconsideration later in the month. The petition specifically requested that the Commission reconsider the low-income bill protections in the pilot so that all low-income customers receive the same bill protections during the pilot, not just those who are LIHEAP recipients. The Commission denied the petition for reconsideration in October 2018.	Docket No. 17-776 Order
Utility Business Model Reform	Minnesota statutes allow utilities to establish multi-year rate plans for a period of up to five years. The same statutes provide that the Commission may require a utility operating under a multi-year rate plan to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies. The Commission noted that during Xcel's most recent rate case, the record was insufficient to determine the adequacy of its performance metrics. The Commission opened a new proceeding in September 2017 to reach an understanding of the combination of metrics and incentives that could appropriately align utility and ratepayer interests. The docket is proceeding in two phases, with the first phase collecting stakeholder input on the key goals for the electricity sector and how to measure its progress toward meeting those goals. The second phase will focus on how those performance measurements could be applied by the Commission. Performance metrics have been under discussion in the E21 stakeholder roundtable on performance metrics. The Commission examined this matter at its November 1, 2018 agenda meeting. The Commission authorized its Executive Secretary to issue notices, set schedules, and designate comment periods for the development of performance incentive mechanisms. The process will also include several stakeholder workshops. The Commission selected Great Plains Institute as a facilitator. On January 8, 2019, the Commission issued an order adopting the performance incentive mechanism development process proposed by the Office of the Attorney General.	Docket No. 17-401 E21 Initiative

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NC	Time-Varying Rates	In August 2017, Duke Energy Carolinas requested various changes to its rates, including a new Grid Modernization Rider. Duke Energy Carolinas and the Public Staff filed a Stipulation of Partial Settlement, which addressed numerous issues in the rate case. A June 2018 Order from the Commission approved the Stipulation but denied Duke's proposed Grid Modernization Rider. Various parties to the docket suggested that Duke should develop additional time-of-use or critical peak pricing options for customers. The Commission, however, was not persuaded based on the pilot rates previously implemented. The order does not adopt new time-of-use or critical peak pricing options, but it does require Duke to file proposed dynamic rate structures in this docket within 6 months. In December 2018, Duke filed a report on plans for AMI and customer connect-enabled rate design, pursuant to the Commission's June order. The report notes that Duke will evaluate a redesigned residential TOU rate, a residential fixed bill rate, a residential variable peak pricing rate, small commercial TOU and variable peak pricing rates, and large commercial/industrial TOU and variable peak pricing rates. Duke noted that it will file at least two pilots (one for residential customers and one for general service customers) at the time of its next rate case.	Docket E-7 Sub 1146 Order Rate Design Report
NH	Energy Storage Tariff	In December 2017, Liberty Utilities filed an application to implement a battery storage pilot program, in which the utility will deploy 5 MW total of battery storage equipment at the homes of 1,000 residential customers. The utility is also requesting approval for a TOU rate for program participants, which includes critical peak, on-peak, and off-peak periods. Multiple parties generally expressed support for the program as a pilot, but concern about the proposed TOU rate not being more broadly available. A settlement agreement was filed in November 2018, which approves the program with modifications. The settlement approves a modified version of the proposed program, and establishes a working group to develop a "Bring Your Own Device" program to deploy 500 additional batteries deployed by third parties. In January 2019, the Commission issued an order approving the battery storage program as detailed in the settlement agreement.	Docket No. 17-189 Order No. 26,209
	Time-Varying Rates	In the New Hampshire Public Utilities Commission's June 2017 net metering successor tariff order, the Commission ordered the implementation of four pilot programs, including one on TOU rates (Eversource and Unitil) and one on real-time pricing (Liberty Utilities / City of Lebanon). The TOU pilots will be open to both residential and small commercial	Docket No. DE 16-576 Order No. 26,029

		customers. The order requires that the data from these pilot programs be made available to a broad range of stakeholders. A working group on TOU rate pilots has been meeting, and one utility previewed a potential TOU rate approach. The working group met again in mid-July 2018.	
NJ	Decoupling	As part of Atlantic City Electric's general rate case filed in June 2018, the utility proposed a decoupling mechanism, designed as an annual rate adjustment. The Division of Rate Counsel filed a motion to dismiss the application on the grounds that it does not include all of the necessary data. The Board of Public Utilities approved the Rate Counsel's motion, dismissing the case in July 2018. Atlantic City Electric refiled its application in August 2018, which includes the proposed decoupling mechanism.	ACE Petition (Docket No. 18080925)
	Decoupling	As part of PSE&G's general rate case filed in January 2018, the utility proposed a decoupling mechanism called the Green Enabling Mechanism. The Green Enabling Mechanism would create a deferral tracking account, in which the difference between allowed and actual distribution revenue is recorded. Over-recovery will result in a rate decrease, and under-recovery will result in a rate increase. In October 2018, the Board of Public Utilities approved a stipulation, which withdraws the utility's request for the Green Enabling Mechanism.	PSE&G Regulatory Filing (Docket No. ER18010029) Decision
	Time-Varying Rates	S.B. 603 and A.B. 3732, introduced in January and March 2018, direct the Board of Public Utilities to open a proceeding to allow the state's utilities to deploy AMI throughout their service territories. Upon completion of the Board's proceeding, each utility is to file a proposed smart meter procurement and installation plan. The bills state that utilities and electric power suppliers may offer TOU rates and real-time pricing programs after deploying AMI. The bills also state that residential and commercial customers may elect to participate in these rate programs.	A.B. 3732 (I) S.B. 603 (I)
NM	Decoupling	Pursuant to the New Mexico Public Regulation Commission's final order approving a modified revised stipulation in PNM's latest general rate case, a new docket was opened in March 2018 to address regulatory barriers and disincentives to energy efficiency and load management programs. The proceeding is intended to provide stakeholders with an opportunity to develop a mechanism to remove these disincentives, which can then be implemented in PNM's next rate case. PNM proposed a Lost Contribution mechanism for the residential and small power service classes to remove these disincentives.	Docket No. 18-00043-UT

		The mechanism would be comprised of an authorized fixed cost recovery factor, a lost fixed cost amount, and a lost contribution rider rate. In December 2018, the Coalition of Clean Affordable Energy, New Mexico Attorney General, and PNM requested that the Hearing Examiner hold the proceeding in abeyance until the end of the 2019 state legislative session. The Hearing Examiner granted the motion.	
NV	Utility Business Model Reform	Nevadans voted on a Constitutional Amendment in November 2016 to deregulate the electric utility industry, the Energy Choice Initiative. Seventy-two percent of voters voted in favor of deregulation. However, Nevada law requires Constitutional Amendments to be approved in two even-numbered years. This amendment will need to be approved by voters again in 2018 before taking effect. At the request of the Governor's Committee on Energy Choice, the Public Utilities Commission of Nevada (PUCN) opened a docket in October 2017 to study the following issues: (1) a prospective timeline for implementing the initiative, (2) amendments or repeals of any current Nevada laws or regulations that may be necessary to establish a competitive market, (3) available options for designing a wholesale electricity market, and (4) available options for designing a competitive retail electric service market. The PUCN also committed to studying the potential short- and long-term financial benefits and risks to residents and businesses. A series of workshops were held in January 2018, after which the PUCN accepted comments. The investigation was completed in April 2018 with the filing of an extensive final report. The final report addresses the various issues it set out to address, and expresses the uncertainty of the future while presenting its findings. Nevadans voted on the Amendment again in November 2018, and rejected it. The Constitutional Amendment will not take effect.	The Energy Choice Initiative - Constitutional Amendment Docket No. 17-10001 Final Report
NY	Rate Reform	As a part of the Reforming the Energy Vision Track Two order, the Public Service Commission (PSC) required the utilities to provide in detail the cost allocation methodologies being used to calculate standby rates. The PSC also directed the utilities to file revisions to their standby service rates to implement offset tariff and reliability credit provisions for standby customers who are able to demonstrate that they are able to reduce their load below contract demand over consecutive summer periods. The utilities filed their tariff amendments in August 2016, which became effective on January 1, 2017 after including revisions ordered by the PSC. In July 2017, the PSC issued an order moving this proceeding into the Value of Distributed Energy Resources (VDER)	Docket No: 17-01277 Docket No. 16-M-0430

	proceeding's Rate Design Working Group (Matter No. 17-01277). The Staff issued a draft outline for a standby/buyback white paper in February 2018. The outline includes a recommendation to require utilities to develop more granular as-used demand charges, with time and location variant components, depending on the cost driver of the distribution system. In December 2018, the Staff published a white paper recommending modifications to existing standby and buyback service rates. In April 2018, the utilities published a Rate Design Handbook to define and explain the uniform approach they have developed for parties to submit rate design proposals for customers with DERs. During Q2 2018, stakeholders submitted proposals based on the framework established by the PSC. In late June 2018, the PSC announced which rate design proposals will be evaluated. The proposals to be evaluated include a TOU rate proposal submitted by the clean energy parties, a TOU rate proposal from PSC Staff, a demand rate proposal from the joint utilities, and a combined demand and TOU rate proposal from the joint utilities. The utilities and the consultant serving the PSC completed rate design evaluations during August 2018, and a working group meeting was held in October to discuss the evaluations.	
Rate Reform	In July 2018, Consolidated Edison (ConEd) filed a proposal for a pilot innovative pricing program. The innovative pricing options will be available to residential and small commercial customers. The options include demand-based rates and subscription rates (fixed monthly charge based on the customers' prior electric demand). Several variations are included to test customer satisfaction, acceptance, behavior, and bill impact. Variations include peak and off-peak demand charges, seasonal demand charges, peak period timing, TOU supply components, and overage charges for subscription rates. In December 2018, the Public Service Commission approved the Innovative Pricing Pilot. ConEd expects to enroll approximately 67,100 customers in the pilot. The pilot will begin in April 2019 and will end after the first quarter of 2022.	Docket No. 18-01597/18-E-0397
Rate Reform	In August 2018, Consolidated Edison filed amendments to its electric tariff to include rates for its Smart Home Rate Demonstration Project Concept, which was initially proposed and reviewed favorably in the main Reforming the Energy Vision docket in 2017. The new rates are for customers participating in two different program tracks; one track has customers receiving price-responsive air-conditioning demand management technology, while the other track has customers receiving price-responsive energy storage.	Docket No. 18-02038/18-E-0548 Docket No. 14-00581/14-M-0101

	The new rates include time-variant energy supply charges, demand charges (based on daily 60-minute peak demand for the demand management customers, but a monthly demand subscription rate for storage customers), and additional peak demand event charges. Energy storage customers would also receive export credits based on energy supply as well as output during generation capacity or transmission and distribution events.	
Rate Reform	In August 2018, Orange & Rockland Utilities filed amendments to its electric tariff to include rates for its Smart Home Rate REV Demonstration Project, which was initially proposed and reviewed favorably in the main Reforming the Energy Vision docket in 2017. The new rates are for customers participating in two different program tracks; one track has customers receiving price-responsive air-conditioning demand management technology, while the other track has customers receiving price-responsive energy storage. The new rates include time-variant energy supply charges, demand charges (based on daily 60-minute peak demand for the demand management customers, but a monthly demand subscription rate for storage customers), and additional peak demand event charges. Energy storage customers would also receive export credits based on energy supply as well as output during generation capacity or transmission and distribution events.	Docket No. 18-02039/18-E-0549 Docket No. 14-00581/14-M-0101
Time-Varying Rates	S.B. 3093 creates a Real Time Smart Meter program to provide residential customers with greater ability to control and manage electricity usage. Customer electing to participate in the program would be charged based on electricity usage and time of usage and a flat fee incorporating a generation bid cost and service size cost. Utilities, subject to Public Service Commission agreement, may delay participation in the program for at least ten years. During this time, other providers would have the opportunity to provide meters. The bill also provides authority to the Commission to establish real time smart meter pilot programs. The bill did not advance during the 2017-2018 legislative session.	S.B. 3093 (D)
Utility Business Model Reform	In May 2016, as part of Track Two of New York's Reforming the Energy Vison proceeding, the Public Service Commission (PSC) directed the utilities to propose a DG interconnection survey process and Earning Adjustment Mechanism (EAM) metrics. The EAM will provide utilities with diverse, balanced financial incentives to implement REV outcomes. In September 2016, the utilities proposed EAM metrics, as well as specific targets and incentives to be developed. In March 2017, the PSC ordered the	Case No.16-01575/16-M-0429

		utilities to file a revised proposal with modifications provided by the PSC. In May 2017, the utilities published a revised EAM proposal, and in August 2017, the utilities filed a supplemental interconnection EAM survey instrument. In October 2018, the Commission Staff filed a proposal related to the interconnection EAM. Several parties filed comments opposing the Staff's proposal.	
	Utility Business Model Reform	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. In December 2018, the PSC adopted an energy storage target and roadmap for deploying 1,500 MW of storage by 2025 and 2,000 MW by 2030. As part of the roadmap, the PSC directed the utilities to file in their next general rate case an Earning Adjustment Mechanism metric for system efficiency. The system efficiency target is to include peak reduction and load factor.	Docket No. 18-00516/18-E-0130 NYSERDA Website
OK	Utility Business Model Reform	In September 2018, as part of a general rate case, Public Service Company of Oklahoma proposed a grid modernization and efficiency plan, which includes the adoption of performance-based rates. The plan would establish certain "performance incentive measures" related to reliability, grid modernization, customer satisfaction, public safety, and economic development, and would set a range of allowable return on equity levels (9.8-10.8%) based on actual financial performance. The reliability incentive is based on SAIDI figures, and the grid modernization incentive is based on the utility executing its grid modernization investment plan on-time and within a certain budget. The customer satisfaction incentive is based on survey results, the public safety incentive is based on responding to reported hazards, and the economic development incentive is based on the utility participating in and supporting local workforce development events. Performance-based rate adjustments would take place annually. Parties filed their lists of major issues for the proceeding on January 2, 2019.	Docket PUD-201800097 Press Release
OR	Time-Varying Rates	In December 2018, Idaho Power filed an application for approval of a TOU pilot rate for its residential customers in Oregon. The rate would be offered on an optional, voluntary basis to customers with AMI installed.	Docket No. ADV 901
RI	Utility Business Model Reform	This proceeding was opened in August 2018 for adoption of performance incentives to apply to the	Docket No. 4857

	electric infrastructure, safety, and reliability plans. Nothing has been filed in the docket. In January 2019, Office of Energy Resources filed to be an intervenor in the proceeding.	
Utility Business Model Reform	In October 2018, National Grid filed its 2019 System Reliability Procurement Report. In the report, the utility proposed performance incentives for 2019 SRP work. The incentives include (1) a 2% (of the 2019 SRP budget) incentive for identifying areas where large non-electric public transportation fleets are located, as part of the work on the Rhode Island System Data Portal; (2) a 2% incentive for identifying locations where electric vehicle fast charging stations can be installed; and (3) a 2% incentive for awarding and completing the first vendor milestone for three non-wires alternatives projects.	Docket No. 4889 2019 System Reliability Procurement Report

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of late January 2019.

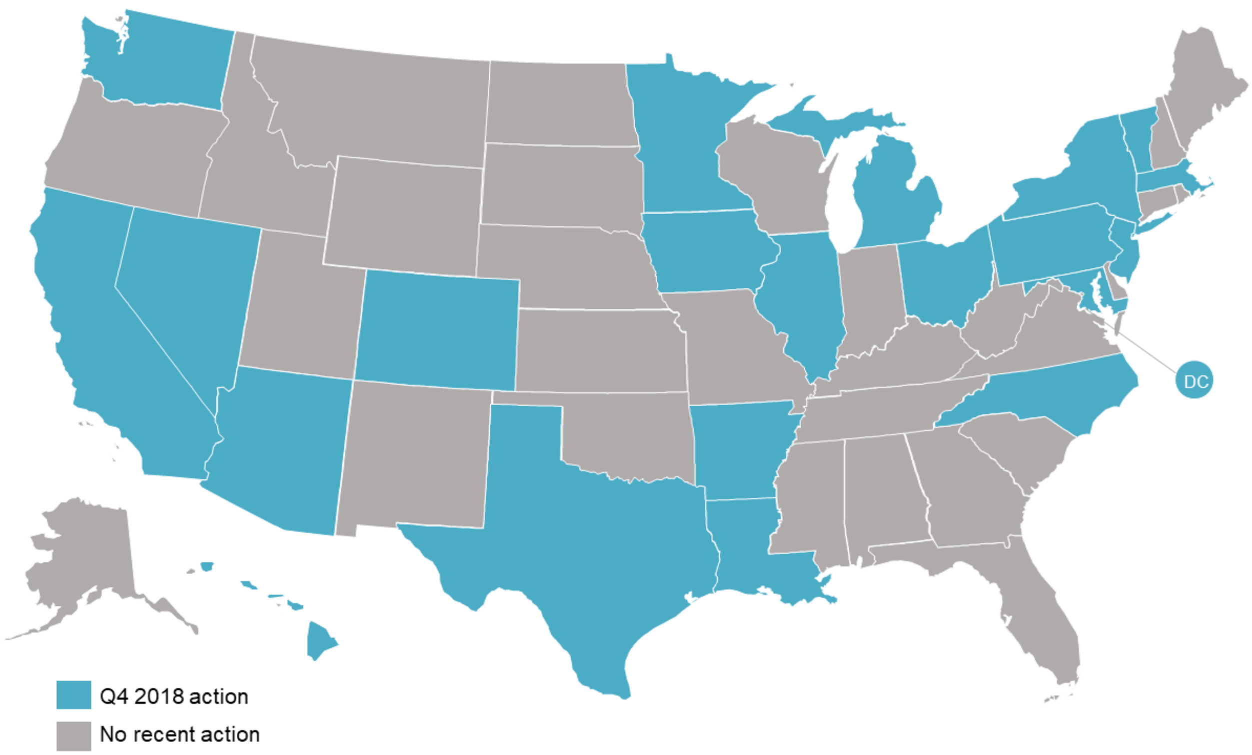
GRID MODERNIZATION POLICIES

Key Takeaways:

- In Q4 2018, 21 states plus DC took 58 actions on grid modernization policies, including energy storage targets, interconnection standards for energy storage, and rules related
- Data access protocols were under consideration in 13 states during the quarter.
- The New York Public Service Commission adopted an energy storage goal of 3,000 MW by 2030.

States are considering many different ways to regulate and encourage the deployment of grid modernizing technologies. In Q4 2018, 21 states and DC took actions related to grid modernization policies, with the most common types of actions concerning advanced metering infrastructure (AMI) rules, data access policies, energy storage targets, and interconnection rules.

Figure 33. Action on Grid Modernization Policies (Q4 2018)



In Q4 2018, 13 states considered provisions for access to customer usage data. The New York Public Service Commission ordered the development of a pilot distributed energy resource (DER) data platform, which would make customer and system data available to DER developers. The Michigan Public Service Commission approved data privacy tariffs for most utilities during the quarter, and the Public Utilities Commission of Ohio opened a proceeding on data access as part of its PowerForward initiative.

The New York Public Service Commission adopted an energy storage goal of 3,000 MW by 2030 in Q4 2018. The storage target was approved along with a roadmap of policy actions to achieve the goal. Following the release of Nevada's energy storage study, the Commission recommended proceeding to a rulemaking to establish a storage procurement target. An energy storage target is also under consideration in Arizona, and the Massachusetts Department of Energy Resources worked to develop the details of its new clean peak standard during Q4 2018.

Box 5. A Note About Policies

Grid Modernization Policies is intended to be a broad category, capturing state-level policy actions related to grid modernization and the deployment of distributed energy resources (excluding solar-specific actions) that do not neatly fit into other categories in this report. The actions in this category are largely centered on market development policies, such as energy storage mandates, as well as regulatory procedures.

The eligibility of solar-plus-storage facilities to net meter was another issue addressed during Q4 2018. The New York Public Service Commission approved a Hybrid Tariff for solar and other generators paired with energy storage to be compensated with New York's Value of Distributed Energy Resources methodology. A proposed decision issued in California would allow large DC-coupled storage systems to net meter if they install power control equipment. In February 2019, the Massachusetts Department of Public Utilities authorized solar-plus-storage systems to net meter under certain configurations.

Figure 34. Most Common Types of Policy Actions in Q4 2018

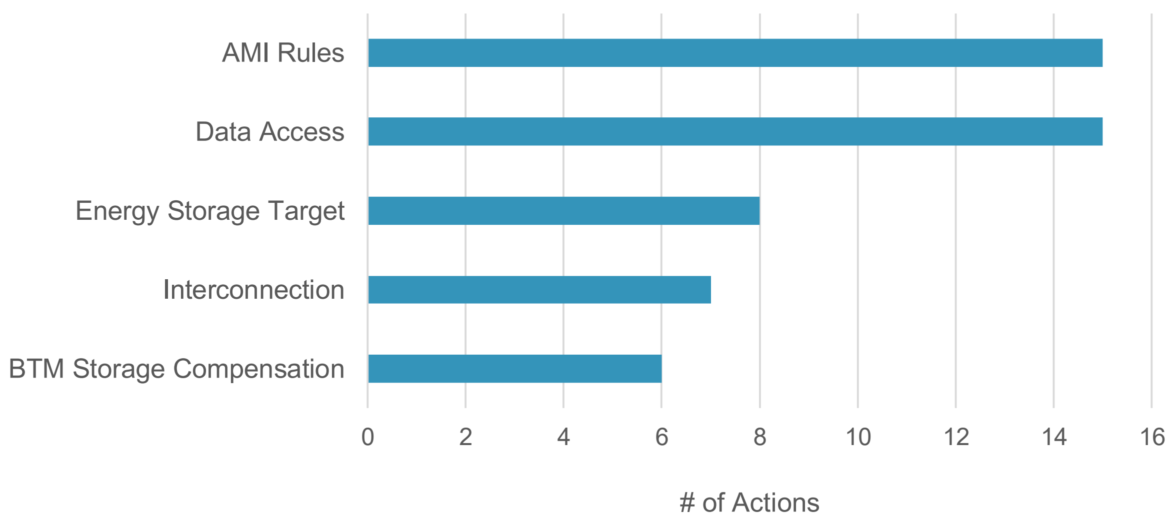


EXHIBIT 4

Table 13. Updates on Grid Modernization Policies (Q4 2018)

State	Policy Type	Description	Source
AR	Data Access	In November 2017, the Arkansas Public Service Commission expanded the scope of a generic proceeding on renewable distributed generation to more broadly consider policy changes related to distributed energy resources, as well as several specific data access questions. These data access issues and questions include identifying public policy goals that third-party aggregation and sharing of data with third parties may further, to what extent should AMI data that does not contain personal information be made available to certain entities, to what extent should AMI data that does not contain personal information be made available under privacy protections to entities wishing to provide AMI benefits to customers, identifying the potential costs and revenue-producing aspects of providing AMI data to third parties, and more. In July 2018, the Commission issued an order, establishing a list of issues to be addressed during the course of the proceeding, including third-party access to utility data, cybersecurity, confidentiality and privacy, and the process for customer consent to access data. The Commission accepted comments on the grouping of issues to be addressed in the proceeding and additional issues, the order and prioritization of these issues, means of addressing and building consensus on these issues, the expertise necessary to address these issues, and possible timeframes for events. The Commission will schedule an initial educational workshop on DER and grid modernization issues. The Commission also deferred action on the electric cooperatives' request for exemption from this proceeding until after the educational workshop.	Docket No. 16-028-U Order No. 10
AZ	Blockchain, Energy Storage, Interconnection, Renewable Portfolio Standard	In August 2018, the Arizona Corporation Commission (ACC) opened a rulemaking docket to evaluate proposed modifications to many of the state's energy rules. Rules to be addressed in the proceeding include the renewable energy standard, energy efficiency standards, resource planning and procurement, retail electric competition, net metering, electric vehicles, DG interconnection, blockchain technology, technological developments, forest bioenergy, baseload security, and the biennial transmission assessment. A workshop to discuss retail electric competition is scheduled for December 3rd. The ACC Staff is developing an electric vehicle draft policy for consideration at the December 17th open meeting. Commissioner Burns filed a list of several	Docket No. RU-00000A-18-0284 Policy Statement Regarding AG-Y Alternative Generation/Buy-Through Program

	electric vehicle-related questions for parties to be prepared to discuss. The ACC Staff filed a proposed policy order in December 2018, which would require the utilities to develop alternative generation/buy-through programs for medium and large commercial customers. In January 2019, the ACC published a policy statement on an alternative generation/buy-through program, which directs Arizona Public Service to expand and modify its current program to allow medium-sized commercial customers to participate or proposed a new program in its next rate case that would allow medium commercial customers to participate. The order also directs Tucson Electric Power and UNS Electric to propose an alternative generation/buy-through program for medium and large commercial and industrial customers in their next rate cases. The policy statement provides guidelines for the design of such a program.	
Clean Peak Standard, Energy Storage Target	In August 2016, Arizona Corporation Commission Chairman Little opened a docket to review, modernize, and expand Arizona's Renewable Energy Standard and Tariff. At the end of November, the Residential Utility Consumer Office filed a proposal to add a Clean Peak Standard to Arizona's RPS. The Clean Peak Standard would require a certain percentage of energy used to meet peak load hours to be derived from clean sources. In late January 2018, Commissioner Tobin filed his proposed Energy Modernization Plan. The proposed plan includes an energy storage target of 3,000 MW by 2030. The plan would also rename the state's Renewable Energy Standard and Tariff to the Clean Resource Energy Standard and Tariff and require that 80% of the state's electricity generating portfolio be comprised of clean resources by 2050. The proposal includes a Clean Peak Target, which will be based upon the current level of clean resources deployed during peak hours and increase by 1.5% on average each year until 2030. In early July 2018, Commissioner Tobin filed a formal set of draft rules implementing his proposed Energy Modernization Plan. Later in July, several Commissioners expressed support for opening a new rulemaking docket to consider changes to the state's Renewable Energy Standard and Commissioner Tobin's Energy Modernization Plan. In August 2018, the Commission opened a rulemaking docket to evaluate modifications to several different energy rules (see Docket No. RU-00000A-18-0284).	Docket No. E-00000Q-16-0289 RUCO Comments Proposed Energy Modernization Plan Notice of Inquiry Draft Rules

Data Access	As part of a recommended order in Tucson Electric Power's DG rate design proceeding, the ALJ directed the utility to develop a web-based process for easy, electronic access to hourly load data for customers requesting this. The Commission issued a final decision in September 2018, approving the ALJ's data access recommendation. In November 2018, TEP filed an update on its data access capabilities and plans.	Docket No. E-01933A-15-0322 Decision No. 76899
Data Access	As part of a recommended order in UNS Electric's DG rate design proceeding, the ALJ directed the utility to develop a web-based process for easy, electronic access to hourly load data for customers requesting this. The Commission issued a final decision in September 2018, approving the ALJ's data access recommendation. In November 2018, UNS filed an update on its data access capabilities and plans.	Docket No. E-04204A-15-0142 Decision No. 76900
Interconnection	Arizona is currently in the process of developing statewide interconnection rules (Arizona does not currently have statewide interconnection standards). In September 2017, the Arizona Corporation Commission Staff published a revised draft of the statewide interconnection rules, which includes new sections on energy storage system and advanced inverter requirements. The Staff requested comments on the draft rules, including in particular, the energy storage and advanced inverter requirements. The draft rules would not require non-exporting energy storage systems to comply with the requirements. Storage systems connecting directly to the utility's distribution system would be required to have the capability to operate in Power Factor Control mode, at any fixed reactive power output, and in Automatic Voltage Regulating mode. A stakeholder workshop was held in November 2017. In February 2018, Commissioner Tobin filed comments, recommending that the rules allow self-reporting with certification of technical compliance for non-exporting battery storage systems to satisfy interconnection requirements. The Commission Staff filed its proposed order in April 2018, which includes energy storage in each section of the rules. The proposed order would allow for inadvertent export from non-exporting energy storage systems under certain conditions and would allow non-exporting storage systems of 10 kW or less to go through an expedited interconnection process. In late November 2018, the Commission Staff filed a new memorandum and proposed order, superseding the one filed in April 2018. The newly revised rules would allow	Docket No. RE-00000A-07-0609 Revised Draft Rules Proposed Order Proposed Order (Nov. 2018)

		non-exporting inverter-based energy storage systems and inadvertent exporting systems of 20 kW or less to go through an expedited interconnection process. The Staff recommend that a rulemaking docket be opened and notice of proposed rulemaking issued by February 2019. In December 2018, the Staff filed proposed revisions, which would remove unnecessary screening requirements for non-exporting systems and amend language related to advanced inverter standards. Commissioner Tobin and Commissioner Olson filed proposed amendments related to energy storage in December as well.	
CA	Demand Response	In January 2017, the state's three major IOUs submitted applications for their 2018-2022 demand response budgets and programs. The California Public Utilities Commission approved the budgets and programs in December 2017, but left the proceeding open to address to several unresolved policy matters. The demand response programs approved by the Commission included an auction mechanism pilot, which is still being assessed. Other issues this proceeding is continuing to explore are pilots for promoting demand response in disadvantaged communities and transmission constrained local capacity areas, a new automated demand response incentive policy, the demand response Capacity Bidding Program, and the demand response Two Percent Reliability Cap. An amended scoping memo filed in May 2018 officially added these issues to the proceeding and extended the deadline for the proceeding to July 17, 2019. The Commission Energy Division hosted a workshop to present interim results of the demand response auction mechanism pilot evaluation in July 2018 and followed up with a series of seven questions for the intervening parties. A decision filed in late November 2018 resolved the remaining issues and declined to authorize additional demand response auction mechanism pilot solicitations. The Commission also filed a ruling in November scheduling a prehearing conference in mid-January 2019 to discuss the filings by the utilities for the FERC Tariff Amendment to Implement Energy Storage and Distributed Energy Resources Requirements, and to discuss next steps for determining demand response baselines.	Docket No. A 17-01-012 Amended Scoping Ruling
	Energy Storage Compensation	A January 2016 decision from the California Public Utilities Commission (CPUC) established a successor tariff to replace net metering when the utilities reach their aggregate caps. Part of this discussion has included net metering options for	Docket No. R14-07-002 Decision No. 18-10-005 (Denial

	PV systems paired with energy storage. In August 2017, the utilities filed a petition for modification of an April 2016 decision that established a net metering bill credit estimation methodology for generating facilities paired with storage. The original methodology required the utilities to perform a customer-specific estimation using a calculator developed for the California Solar Initiative. The utilities instead asked to use a single kWh per-kW profile for each climate zone. Decision 18-02-008 of February 2018 granted the utilities their petition for modification. The parties are still awaiting a ruling from the CPUC on a separate petition for modification filed by the California Solar and Storage Association (formerly the California Solar Energy Industries Association) in September 2017 regarding the ability of solar plus storage systems to export solar-generated electricity from the storage system. A proposed decision issued in August 2018 addressed a petition for modification of a previous decision to modify the definition of "small" net metering systems paired with energy storage from less than or equal to 10 kW, to less than or equal to 30 kW. The proposed decision denies the petition. A proposed decision issued in late December 2018 sets the requirements for equipment for larger DC-coupled systems; these systems will be able to net meter if they install power control equipment to prevent storage systems from charging from or exporting to the grid. An earlier proposed decision would have allowed the use of an ex post data verification option, which is not allowed in this decision.	of modification of small NEM paired with storage)
Energy Storage Target	S.B. 1347, introduced in February 2018, requires the state's three IOUs to collectively procure an additional 2,000 MW of energy storage by January 1, 2020. The bill passed the Senate in May 2018, but died in the Assembly at the end of the legislative session.	S.B. 1347 (D)
Interconnection	In March 2018, Southern California Edison (SCE) filed proposed revisions to its Wholesale Distribution Access Tariff (WDAT) with FERC to facilitate the interconnection of energy storage devices to its distribution system and conform its interconnection procedures with those of California ISO. SCE's proposal sought to curtail electricity service to customers with energy storage before other retail customers during times of peak demand. FERC accepted some of the revisions, but rejected the revisions pertaining to energy storage. In rejecting it, FERC argued that SCE failed to demonstrate why it is just and reasonable to curtail one class of interconnection customer's	Docket No. ER18-1248

		load without providing an opportunity to have the energy storage device's load studied. SCE submitted a revised tariff in September 2018 in response to FERC's critiques. FERC accepted the revised tariff in October 2018.	
CO	Energy Storage Compensation	The Colorado Public Utilities Commission opened a proceeding in October 2017 to consider changes to rules concerning the Renewable Energy Standard, as well as net metering, electric resource planning, and acquisitions from qualifying facilities, and distribution system planning. One question the Commission noted it is particularly interested in is the eligibility of net metering for solar systems paired with storage. Working groups met several times throughout the summer, and parties submitted comments and proposed rule changes in early September 2018. A law enacted in March 2018 established that solar-plus-storage systems are eligible for net metering. In Xcel Energy's final comments, the utility proposed language amending Colorado's net metering rule to implement the new law's requirements. The language would not require the installation of an additional load meter for monitoring an energy storage system. The Joint Solar Parties also proposed language allowing customer generation facilities paired with energy storage to net meter as long as the storage is charged exclusively from the generating facility or the storage system is designed to not export energy, excluding inadvertent exports. The proceeding was closed on October 31, 2018; the PUC indicated it is considering issuing a Notice of Proposed Rulemaking related to the suggestions from this docket.	Docket No. 17M-0694E
DC	Data Access	A DC bill, introduced in April 2018, establishes the Distributed Energy Resources Authority, an independent authority that has a separate legal existence within the District government. Among other duties, the Authority would provide an API for customer access to energy usage data. Third parties entering into an energy data agreement with the consumer would also be granted access to the data. This data would be provided in real time. The bill also directs the Authority to provide access to anonymous energy data under certain conditions.	B22-0779 (I)
HI	Data Access	In June 2018, the HECO Companies filed an application for Phase 1 of its grid modernization project, spanning 2019 - 2023 at a total estimated cost of approximately $86.3 million. Phase 1 includes the deployment of advanced meters, a	Docket No. 2018-0141

	meter data management system, and a telecommunications network. The proposed meter data management system would include a customer energy portal. The proposal does not mention third party access to customer data. The Division of Consumer Advocacy filed a Statement of Position in November 2018 citing concerns with the application but ultimately recommending it subject to multiple conditions based on the urgent need to begin smart meter deployment. In December 2018, the HECO companies submitted a reply statement in response to the Division's Statement of Position, defending the companies' proposal.	
Energy Storage Compensation	Hawaii phased out traditional net metering in 2015, adopting new interim tariffs and initiating a discussion on successors to these tariffs. The Public Utilities Commission issued a decision and order in October 2017 adopting new tariff options for customers with on-site generation, and in some cases, energy storage systems. The new Smart Export Program targets customers with solar PV and battery storage, with storage systems recharging the battery during the day and discharging in the evening. Customers may power their homes with the battery in the evening or export to the grid in exchange for a monetary credit on their electricity bill. The credit rates range from $0.11 per kWh to $0.21 per kWh, depending on the island. In a March 2018 order, the Commission required the HECO companies to make changes to both tariffs related to control equipment. In Q2 2018, HECO resubmitted its new tariffs and its policy and procedure for allowing net metering customers to add non-exporting energy storage systems. The Commission issued an order in June 2018, addressing a number of outstanding issues. Through the order, the Commission: (1) approved HECO's smart export tariff sheets and net metering policy proposal, (2) invited comments on its CGS+ tariff, and (3) modified the procedural schedule. A September order approved HECO's CGS+ tariff with certain modifications. An October 2018 order also approved in part, HECO's revised tariff for enabling existing net metering customers to install non-export technology and remain in the traditional net metering program.	Docket No. 2014-0192 Order No. 34924 Order No. 35369 Order No. 35563
Interconnection, Microgrid Compensation	H.B. 2110, enacted in July 2018, requires the Public Utilities Commission to open a proceeding by July 1, 2018 to establish a microgrid services tariff designed to provide fair compensation for electricity, grid services and other benefits. The	H.B. 2110 (E) Docket No. 2018-0163

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		Commission opened a proceeding in July 2018 to develop a microgrid services tariff. A November order scheduled a technical conference for January 9, 2019, and established deadlines for opening briefs and reply briefs in February 2019.	
IA	AMI Rules	In January 2018, the Iowa Utilities Board sent a letter to Interstate Power & Light Company (IPL) requesting a response to customer complaints about installation of advanced meters, specifically asking whether customers are allowed to opt out of installation, whether installed meters are fully functional, and whether IPL would remove an advanced meter if a customer's health is affected by it in the view of a medical professional. In February 2018, IPL filed a response laying out its planned opt out provision, explaining that meters would become fully functional once all communication infrastructure is installed no later than September 2019, and explaining that advice from a medical professional would not entitle customers who would otherwise be unable to opt out (i.e. those who self-generate or are on time-of-use rates) to opt out (the standard opt-out provision would be available to everyone not in those categories). In March 2018, Interstate Power & Light filed a proposed tariff for residential customers that would charge a $15 monthly fee to any customers who opt out of having a smart meter installed. Customers who opted out would also need to provide a monthly manual meter reading to the utility. In July 2018, the Utilities Board merged this proceeding and the proceeding regarding customer complaints (Docket No. C-2018-0006) into one “master” docket (Docket No. SPU-2018-0007). Hearings were held in November and December 2018.	Docket No. C-2018-0006 Docket No. TF-2018-0029 Docket No. SPU-2018-0007
IL	Data Access	In March 2017, the Illinois Commerce Commission opened a docket to investigate the creation of a third-party warrant process for access to customer AMI data. The issue had earlier been dismissed from Docket No. 14-0507 for consideration in a separate docket. Two motions to dismiss the proceeding were filed in October 2017 (one by the Illinois Attorney General, another by the Illinois Competitive Energy Association). These motions would result in no third-party warrant process being created. The motions were denied in May 2018. Parties filed reply comments in December 2018.	Docket No. 17-0123
LA	Data Access	In June 2018, the New Orleans City Council opened a rulemaking proceeding to consider revising the city's customer service regulations to	City Council Docket No. 18-04

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		allow Entergy New Orleans to disclose whole-building energy use data to owners of buildings with four or more meters without first obtaining authorization from tenants. The Council accepted comments on this topic, as well as mapping meters to buildings and automating data aggregation and transmission. The City Council's Utility Advisors filed a report with recommendations in October 2018. The Advisors recommend that only whole-building data be released and that data for a subgroup within a building should not be released. The Advisors recommend that these buildings must have at least four active meters and at least four unique customers to allow data to be released. Data would be released to only building owners or an owner's designated representative upon request. On December 20, 2018, the City Council adopted a resolution and order revising customer service regulations to allow the release of aggregated whole-building data to building owners under certain conditions. The resolution directs Entergy New Orleans to file draft processes for the release of whole-building data and further information on the costs and benefits to ratepayers of releasing this data prior to the full implementation of AMI.	Advisors' Report Resolution No. R-18-539
MA	Clean Peak Standard	The Department of Energy Resources (DOER) is developing rules to implement Chapter 227 of the Acts of 2018, which adopted a clean peak standard for the state. In December 2018, DOER determined that approximately 0 MWh are currently being served by existing clean peak resources during peak load hours and set the minimum standard percentage requirement for the 2019 compliance year at 0%. In January 2019, DOER released draft questions to receive stakeholder feedback on. Many of the questions relate to which types of resources should be eligible for compliance, how the seasonal peak periods should be established, and how compliance should be handled. Responses to the questions are due by February 5, 2019.	Massachusetts Clean Peak Standard
	Data Access	A pair of bills introduced in 2017 increase the availability of energy data in the state. The bills require the state's investor-owned utilities to provide access, upon request by a municipal official, to aggregate annual energy consumption data by sector for up to five prior years, as well as anonymized annual energy consumption data by household, daily 15-minute peak demand data for commercial and municipal buildings for up to one prior year, and aggregate daily 15-minute peak demand data for the residential sector. The bills	H.B. 3386 (D) S.B. 1858 (D)

	did not advance during the 2017-2018 legislative session.	
Energy Storage Compensation	In October 2017, the Department of Public Utilities (DPU) opened an inquiry into the net metering eligibility of solar plus storage systems (or energy storage paired with other types of eligible net metering systems), as well as the eligibility of net metering facilities to participate in the Forward Capacity Market. Comments and reply comments were accepted on six questions related to storage eligibility: (1) Should energy storage systems be allowed to net meter? (2) Should only certain types of energy storage systems be allowed to net meter? (3) What technical requirements would be necessary so that the storage system and net metering facility can both participate in the ISO New England energy and capacity markets? (4) What process could ensure that the storage system is only charged by the net metering facility and does not export power to the grid? (5) What other requirements would be necessary to safeguard against gaming and manipulation of net metering rules? (6) Should the net metering cap allocation reflect the combined capacity of the net metering facility and storage system, and should there be a distinction between existing and new net metering facilities? A technical conference was held in late January 2018. A technical conference on the eligibility of net metering facilities to participate in the Forward Capacity Market was held in June 2018, following the release of a straw proposal from the DPU Staff. Following the conference, the Staff published a revised straw proposal and solicited comments on several questions, including if a host customer or SMART project owner should have sole authority to assert title to an energy storage system's capacity rights and if the DPU should treat a storage system's capacity differently than the capacity of a net metering SMART program facility it is co-located with. The DPU also requested comments on a definition for inadvertent export to the electric distribution system, and what types of configurations could experience this. Following the conference, the DPU accepted comments and reply comments on its revised straw proposal during July.	Docket No. 17-146
Energy Storage Target	Companion bills introduced in Massachusetts direct the Department of Energy Resources (DOER) to establish a statewide deployment target of 1,766 MW of cost-effective energy storage to be developed by January 1, 2025. The proposed legislation also directs DOER to set a subsequent	H.B. 1746 (D) S.B. 1874 (D)

		deployment target on or before December 31, 2020 to be achieved by January 1, 2030. The targets are to include both minimum and maximum limits on the amount of storage that may be owned by load-serving entities and are to be reevaluated every three years. The legislation also permits DOER to consider policies to encourage storage deployment. The bills did not advance during the 2017-2018 legislative session.	
MD	Data Access	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to ensure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. A working group to examine Competitive Markets and Customer Choice was established as part of this process, and in late June 2017, the group filed a request to seek comments and hold a hearing to support the development of regulations pertaining to customer interval data access. In January 2018, the Competitive Markets and Customer Choice working group recommended that the PSC initiate a rulemaking proceeding to consider the group's proposed Phase II regulations (related to instant connects and seamless moves). The group also recommended that the PSC address the proposed data access regulations filed in June 2017, which remain substantively unchanged. The Commission agreed and opened Rulemaking No. 62 in March 2018, and accepted comments through April 2018. The Commission held rulemaking sessions in May and August 2018. The next rulemaking session is scheduled for February 6, 2019.	Public Conference No. 44 Rulemaking No. 62
	Interconnection	In December 2017, the Maryland Public Service Commission initiated a rulemaking proceeding to consider revisions to the state's small generation interconnection process, as recommended by stakeholders in the Public Conference 44 Interconnection Working Group. The working group reached consensus on making the interconnection process more efficient, allowing applications to be filed electronically, removing monitoring for systems less than 2 MW, and other improvements. The proposed regulations include (1) the addition of energy storage provisions, (2) amendments to the interconnection process for systems larger than 25 kW and less than 2 MW, as well as a number of other minor changes. Rulemaking sessions were held in January, April, and September 2018.	Public Conference No. 44 Rulemaking No. 61

MI	AMI Rules	H.B. 4220, introduced in February 2017, allows utility customers to opt out of having an advanced meter installed; utilities would only be able to install advanced meters if the customer did not opt out and choose to retain a traditional meter. This bill applies to both IOUs and municipal utilities. The bill did not advance during the 2018 legislative session.	H.B. 4220 (D)
	AMI Rules	S.B. 1128, introduced in September 2018, requires utilities to allow customers to choose between having a traditional or an advanced meter, and prohibits utilities from charging fees to allow use of a traditional meter, unless the customer is unwilling to report usage, in which case the monthly fee could not exceed $5.00. The bill also creates data privacy and encryption requirements; utilities would not be able to sell or otherwise share energy usage data, and would be required to encrypt data so that it could not be intercepted by non-utility equipment. The bill did not advance during the 2018 legislative session.	S.B. 1128 (D)
	AMI Rules	In March 2018, Indiana Michigan Power filed a request to implement a tariff for customers who wish to opt out of AMI installation. Customers opting out of AMI would be charged a one-time fee of $44.07 (or $81.30 if the meter has already been installed) as well as a monthly charge of $16.77 for meter-reading expenses. A settlement agreement was filed in early October 2018; in the settlement, the one-time fee would remain at $81.30 for customers opting out after a meter has been installed, but there would not be a one-time fee for customers opting out before a meter has been installed. A monthly fee of $16.40 for meter-reading expenses is also included. The settlement was approved in late October 2018.	Docket No. U-20137
	AMI Rules	In September 2018, as part of a general rate case, Upper Peninsula Power Company (UPPCO) proposed deploying AMI for all of its residential and small commercial customers. There will be an opt-out process for customers who do not wish to have an advanced meter installed; customers opting out would need to pay a $14.26 monthly meter-reading fee, and customers who opt out after an advanced meter is already installed will also need to pay a $62.25 one-time fee to exchange their meter. In early December 2018, the parties filed an agreement extending the schedule of the proceeding by 30 days. Initial testimony is due by February 21, 2019, and a final order is expected in August 2019.	Docket No. U-20276

	Data Access	In December 2017, the Michigan Public Service Commission (PSC) opened a proceeding to process data privacy tariffs utilities are required to file under the newly promulgated Michigan Administrative Code R460.153. All utilities filed data privacy tariffs during the Q2 2018. The Commission requested that the utilities file revised tariffs to ensure that the tariffs contain clear instructions for how a customer (or authorized third party) could access their usage data. All utilities filed revised tariffs in July and August 2018. In late October 2018, the PSC issued an order approving the tariffs filed by all utilities except the tariff from DTE Energy; the PSC was concerned that DTE's data access system would not allow authorized third parties to access usage data independently (the customer would need to send the data to the third party), and directed DTE to file an updated tariff by December 14, 2018. The PSC also directed Commission Staff to convene a forum of interested parties to discuss developing more refined, clear, and consistent language addressing data privacy and data accessibility. A report of findings and recommendations from the forum is due by April 15, 2019. DTE filed its revised data privacy tariff in December 2018.	Docket No. U-18485 Michigan Administrative Code
MN	Interconnection	The Minnesota Public Utilities Commission has an open proceeding to update the state's interconnection standards. The Commission opened a comment period in February 2018 to receive input on the Commission Staff's recommended updates to the interconnection standards. The updated standards are based on FERC's Small Generation Interconnection Procedures, and includes provisions to allow energy storage, both connected to a small generator, and as a standalone device. The Commission held a meeting in May 2018 to receive input on the staff proposal, and approved the new standards in August 2018. Some issues were left unresolved by the August order, and the DG working group met again in November 2018 to resolve the remaining issues. An updated draft of the interconnection standards was released in late November 2018.	Docket No. 16-521 Order
NC	Data Access	As part of the 2016 Biennial IRP and Renewable Energy Portfolio Standard Compliance proceeding, North Carolina's IOUs were required to submit their five-year Smart Grid Technology Plans. The plans vary and include a wide mix of smart grid technologies, including AMI and, in Dominion's case, a microgrid project. The Utilities Commission approved the utilities' plans in March 2017, but	E-100 Sub 147 Duke Energy 2017 Smart Grid Technology Plan Order

	also requested that the utilities, Public Staff, and all interested parties continue discussing potential rule changes for customer data access. Duke Energy addressed its ongoing data access discussions in its updated 2017 Smart Grid Technology Plan in October 2017, saying it has not had any additional formal discussions with the North Carolina Sustainable Energy Association (NCSEA) or the Public Staff regarding potential rule changes, but it remains willing to engage. In its March 2018 order accepting the utility plans, the Commission directed Duke to convene meetings with NCSEA, the Public Staff, and other interested parties to discuss guidelines for access to customer usage data. The first meeting took place in May 2018, and Duke filed a summary of the meeting in the docket in June. The participants agreed to establish four breakout discussion groups: (1) data definition, (2) cost, (3) compliance and authorization, and (4) customer experience. Meetings were held throughout Q3 2018.	Meeting Notes
Interconnection	Following the adoption of revised interconnection standards in 2015, the North Carolina Utilities Commission (NCUC) directed the Public Staff to convene stakeholders in two years to discuss the functioning of the new standards. Advanced Energy, the entity assigned by the Public Staff to facilitate the stakeholder process created four working groups during Q2 2017. One of the working groups is examining new technologies, including energy storage. The working groups held multiple stakeholder meetings, and the Public Staff submitted its report to the NCUC in December 2017. The Public Staff states that no consensus was reached regarding what revisions should be made to the interconnection standard. A redlined version of the standard was included with comments and proposals from all participants identified. The NCUC issued an order in December calling for all parties to submit initial comments. Parties filed comments during Q1 2018, with all parties agreeing on allowing the interconnection rules to apply to energy storage. An October order approved interim modifications to the interconnection procedures to accommodate Tranche 1 of the Competitive Procurement RFP, and established that further changes will be considered via testimony in November and December, followed by an evidentiary hearing in January 2019. The interim modifications do not reference energy storage. A solar developer filed a motion to stay the effectiveness of a portion of the Commission's decision, which the Commission granted in November 2018. The stay made no	Docket No. E-1 Sub 101 Redlined Interconnection Standard Order

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		mention of the Commissions rulings related to storage.	
	PURPA Rules	H.B. 589 of 2017 requires Duke Energy to procure 2,660 MW of renewable energy through a competitive procurement program occurring through four solicitations over a 45-month period. The competitive procurement program is the state's new PURPA implementation mechanism. A February 2018 order from the North Carolina Utilities Commission (NCUC) approved the joint program proposed by Duke Energy Carolinas and Duke Energy Progress, and the use of Duke's proposed pro forma purchase power agreement (PPA) in the Tranche 1 solicitation. Duke Energy filed a revised pro forma PPA in May 2018, which included new requirements for energy storage projects that were not included in the original. The North Carolina Sustainable Energy Association and the North Carolina Clean Energy Business Alliance filed a joint motion requesting that the Commission order Duke to remove all of the recently added energy storage provisions until there is stakeholder consensus and approval from the Commission. A June 2018 order from the Commission denied the joint motion and approved the revised pro forma PPA. The first solicitation will be going forward with the energy storage requirements in place, but a motion for clarification was filed in July 2018 for the Commission to confirm that the energy storage provisions will not automatically be included in the pro forma PPA for future tranches. A July order confirmed that Duke will need to refile its pro forma PPA for each future tranche, and that the energy storage provisions can be reconsidered in them. The Commission issued another order in October 2018 addressing changes to the Interconnection Procedures as they relate to the competitive bidding process. A solar developer filed a motion to stay the effectiveness of a portion of the Commission's decision, which the Commission granted in November 2018. The stay made no mention of the Commissions rulings related to storage. In December 2018, the Commission issued an order directly Duke Energy to file a status report and results from the Tranche 1 solicitation and authorized the utilities to implement the program plans and open the Tranche 2 solicitation in July 2019. Parties may file comments on the program plans by January 31, 2019.	Docket No. E-7 Sub 1156 Docket No. E-2 Sub 1159 Pro Forma PPA Tranche 1 Order
NJ	AMI Rules	A.B. 2994, introduced in February 2018, prohibits utilities from installing smart meters unless the customer has provided written consent and been	A.B. 2994 (I)

		provided with a disclosure detailing the type of data that will be transmitted and how it will or will not be shared.	
	AMI Rules	S.B. 54, introduced in January 2018, requires utilities to install smart meters at the request of the customer. The bill also provides that these costs will be recoverable in a utility's rate base.	S.B. 54 (I)
	AMI Rules	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Cloud Program includes deployment of AMI throughout PSE&G's service territory. PSE&G proposed a $20 monthly fee for residential customers opting out of AMI installation, while commercial and industrial customers will not have the option of opting out. Residential customers requesting the replacement of a smart meter with a traditional meter will be charged a one-time fee of $45.	PSE&G Regulatory Filings (Docket No. EO18101115)
	AMI Rules, Data Access	S.B. 603 and A.B. 3732, introduced in January and March 2018, direct the Board of Public Utilities to open a proceeding to allow the state's utilities to deploy AMI throughout their service territories. Utilities would be required to obtain customer approval before installing each smart meter. The proceeding is also to address data access issues. Upon completion of the Board's proceeding, each utility is to file a proposed smart meter procurement and installation plan. Costs may be recovered in a utility's rate base, although lost or reduced revenue due to reduced electricity consumption will not be considered.	A.B. 3732 (I) S.B. 603 (I)
NV	Energy Storage Target	S.B. 204, enacted in May 2017, requires the Public Utilities Commission of Nevada (PUCN) to determine whether it is in the public interest to adopt annual requirements for the procurement of energy storage by utilities. In making the determination, the PUCN must study all measurable costs and benefits. In July 2017, the PUCN opened a docket to implement the legislation, and workshops were held in November 2017 and February 2018. The PUCN also held a teleconference in November to discuss a proposal from Tesla for a third-party to study the costs and benefits of storage in Nevada. The teleconference participants agreed on a process and schedule for determining the scope of work for a third-party	S.B. 204 (2017) Docket No. 17-07014 The Economic Potential for Energy Storage in Nevada (The Brattle Group) Order (Dec. 2018)

		study. The Governor's Office of Energy issued the 2018 Nevada Energy Storage Study RFP in February 2018, and later selected the Brattle Group to conduct the study. The Brattle Group submitted its energy storage study in early October 2018. The study finds that by 2020 up to 175 MW of utility-scale battery storage could be deployed cost-effectively statewide, increasing to 700 MW - 1,000 MW by 2030. Additionally, behind-the-meter storage could add up to 30 MW of storage capacity by 2030. In December 2018, the Commission issued an order accepting the report and its recommendation to proceed to a rulemaking phase to develop a regulation establishing an energy storage target.	
NY	AMI Rules	A.B. 3066 and S.B. 7214 require AMI devices to meet certain performance and safety standards, and would allow customers the ability to opt out of AMI installation at no penalty, fee, or service charge. The bills did not advance during the 2017-2018 legislative session.	A.B. 3066 (D) S.B. 7214 (D)
	AMI Rules	S.B. 6464 prohibits the deployment of AMI unless certain performance and safety standards are met. The proposed legislation would allow customers to opt out of AMI installation at no charge. The bill did not advance during the 2017-2018 legislative session.	A.B. 6464 (D)
	AMI Rules	The "New York Grid Modernization Act" (A.B. 7480) directs utilities to invest in smart grid deployment if, after a study on the matter is conducted, it is determined that doing so is in the public interest. The bill notes that as part of this deployment, utilities must allow any customer to decline AMI installation at no fee. The bill did not advance during the 2017-2018 legislative session.	A.B. 7480 (D)
	AMI Rules	S.B. 3093 creates a Real Time Smart Meter program, in which customers would have the option of continuing with their current metering system, as well as purchasing or renting a real time smart meter from a third party certified by the Public Service Commission. The bill did not advance during the 2017-2018 legislative session.	S.B. 3093 (D)
	Data Access, Energy Storage Target	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. In December 2018, the PSC adopted an energy storage target and	Docket No. 18-00516/18-E-0130 NYSERDA Website

	roadmap for deploying 1,500 MW of storage by 2025 and 2,000 MW by 2030. The Commission also directed the utilities to work with NYSERDA to develop a pilot DER data platform including customer and system data to aid DER developers.	
Energy Storage Compensation	A.B. 10474 and S.B. 8273 allow any utility customer who begins net metering before December 31, 2021 to continue net metering under current rules for the life of the generating equipment. The bills also require the Public Service Commission to develop a new value of DER methodology that includes various social, economic, and environmental benefits. The bills also increase the system size limit for non-residential net metered systems from 2 MW to 5 MW. This bill passed the Assembly in June 2018, but died in the Senate at the end of the legislative session.	A.B. 10474 (D) S.B. 8273 (D)
Energy Storage Compensation	As part of New York's Reforming the Energy Vision (REV) proceeding, the Public Service Commission (PSC) is implementing a Value of Distributed Energy Resources tariff. The Commission is continuing to revise the tariff and address issues related to DER compensation. In June 2018, the utilities submitted a draft tariff for combined solar and storage systems. In early October 2018, several parties filed comments expressing concern with the draft tariff's compensation system for energy sent to the grid by the energy storage system. Under the draft tariff, energy from the energy storage system would be compensated through a separate value stack than energy produced directly by the solar system. Commenters expressed concern that this could result in the emission reduction value of energy produced by the solar system and stored in the battery being neglected. Commenters suggested alternative ways of dealing with this issue; two commenters suggested using an "electron tagging" system to assign emission reduction value to a certain proportion of energy from storage systems, while another commenter suggested making solar + storage systems that charge the storage exclusively with electricity from the solar system be allowed full value stack participation. In July 2018, the PSC Staff published a white paper on compensation of DER for avoided distribution costs. Staff suggested that the current compensation methods, based on demand reduction value (DRV) and locational system relief	Docket No. 15-02703/15-E-0751 NYSERDA VDER Website

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	value (LSRV), are too complicated and uncertain for developers to take into account when planning projects, and suggested simplifying the DRV and phasing out the LSRV. In September 2018, the Public Service Commission issued an order expanding eligibility for value stack compensation to additional types of resources, including stand-alone energy storage systems. Stand-alone storage systems eligible for value stack compensation must be 5 MW or less in capacity; regenerative braking systems are also included in the eligibility expansion. This order follows the recommendations of a Staff whitepaper on value stack eligibility expansion published in May 2018. In December 2018, the PSC issued an order accepting the hybrid tariff for Distributed energy systems that include battery storage (hybrid facilities). The tariff includes four options: Options A and B offer an environmental credit value, the market transition credit, and capacity credit value for all grid exports by ensuring that only renewable energy is injected to the grid. Option C uses multiple meters to determine whether injections are from renewable energy or not, and Option D uses monthly netting.	
Energy Storage Target	S.B. 2699 requires the Public Service Commission (PSC) to initiate a proceeding to determine energy storage targets that can be achieved by 2021. The procurements targets would be established by December 2018. The PSC is also to establish a deployment policy to reach this goal. The bill did not advance during the 2017-2018 legislative session.	S.B. 2699 (D)
Energy Storage Target	A.B. 8921 and S.B. 7318 direct the Public Service Commission to establish an energy storage goal for the state to be achieved by 2030. This goal is to be set by December 31, 2018. The Governor signed the bills into law in November 2018.	A.B. 8921 (E) S.B. 7318 (E)
Energy Storage Target	A.B. 11099 and S.B. 8602 amend the requirements to be introduced by A.B. 8921/S.B. 7318 regarding establishing an energy storage goal for 2030. These bills require the Public Service Commission to consult with the federally designated electric bulk system operator for New York in developing the energy storage goal, and require that in the event there is a procurement process for energy storage under the target, that such a process use competitive bidding. The bills were signed into law in December 2018.	A.B. 11099 (E) S.B. 8602 (E)

	Interconnection	In January 2018, the Public Service Commission (PSC) began soliciting comments on proposed changes to New York's Standardized Interconnection Requirements (SIR). The PSC Staff proposed adding energy storage systems to the SIR. In April 2018, the PSC issued an order adopting the proposed changes and directing utilities to submit a draft tariff for a combined solar and storage system. In June 2018, the utilities submitted a draft tariff for combined solar and storage systems (see above Docket No. 15-E-0271). In July 2018, the utilities filed their SIR updates. In October 2018, the PSC issued an order modifying the SIR application requirements for energy storage systems. The utilities filed compliance tariffs later in October.	Docket No. 18-00099/18-E-0018 Interconnection Proposal for Storage
	Public-Private Partnerships	A.B. 10079 authorizes the New York Power Authority and Long Island Power Authority to enter into public-private partnerships to construct, repair, replace, reinforce, modernize, or expand the state's electric transmission system. The bill did not advance during the 2017-2018 legislative session.	A.B. 10079 (D)
	Self-Directed Program	Legislation introduced in January 2017 requires the New York Public Service Commission to create a self-directed program for promoting renewable energy, microgrids, fuel fells, and energy storage technologies. The bills did not advance during the 2017-2018 legislative session.	S.B. 1225 (D) A.B. 1705 (D)
OH	Data Access	In December 2017, First Energy filed a plan outlining a three-year $450 million investment in the modernization of its distribution network. The utilities, Commission Staff, and other parties filed a stipulation in November 2018, which includes data access enhancements for customers and competitive suppliers. The enhancements include a customer portal, with data downloadable in Green Button format. The Attorney Examiner established a procedural schedule in November 2018 to consider the stipulation, with an evidentiary hearing commencing on February 4, 2019.	Docket No. 17-2436-EL-UNC Stipulation
	Data Access	The Public Utilities Commission of Ohio (PUCO) opened three new dockets in October 2018 to build upon the PowerForward investigation. The Data and Modern Grid Workgroup docket will address the following tasks: creating protocols for data privacy protections; driving toward real-time or near real-time data becoming available; and prescribing methodology for competitive retail electric service (CRES) providers and other third	Docket No. 18-1597-EL-GRD

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		parties to obtain customer energy usage data, including a method for CRES providers to obtain the total hourly energy obligation, peak load contribution, and network service peak load. The Commission directed staff in late November 2018 to issue a request for proposal for consulting services to assist with the facilitation of the Data and Modern Grid Workgroup. In January 2019, PUCO selected EnerNex to assist with facilitation of the working group.	
PA	Data Access	As part of a settlement filed in September 2018 in Duquesne Light Company's general rate case, the utility will provide anonymized aggregate energy usage data for residential multifamily buildings of at least 50,000 square feet. The settlement was approved in December 2018.	Docket No. R-2018-3000124 Settlement Agreement
	Energy Storage and Microgrid Rules	H.B 1412 allows electric distribution companies to propose energy storage and microgrid pilot programs with the goals of facilitating the use of diverse electric supply options and enhancing electric distribution, resiliency, and operational flexibility. Within five years of approval of the first pilot program, the Commission is to initiate a rulemaking evaluate the circumstances where utility deployment of energy storage and microgrids is in the public interest and to develop regulations to further the deployment of energy storage and microgrids in the state. The bill specifically states that the rulemaking shall not require utilities to own, develop, or deploy energy storage or microgrids. The bill did not advance during the 2017-2018 legislative session.	H.B. 1412 (D)
TX	AMI Rules	In July 2018, the Texas Public Utilities Commission opened a proceeding to review Section 25.130 of the Texas Administrative Code, which contains rules on advanced metering. Later in July 2018, AEP Texas, CenterPoint Energy Houston, Oncor, and Texas New Mexico Power submitted a joint proposal of suggested revisions to the rules. The utilities' suggested changes include removing the requirement that advanced meters provide a means for retail electric providers (REP) to provide price signals to customers, removing the requirement that advanced meters provide home area network (HAN) functionality, and removing the provision allowing REPs to require transmission and distribution utilities to provide non-standard meters or meter features. The utilities also proposed that a process be created through which the minimum service features for advanced meters could be amended by the Commission. No action occurred during Q4 2018.	Docket No. 48525 16 TAC Section 25.130

VT	Renewable Portfolio Standard	As part of the Department of Public Service's report evaluating utility compliance with Tier III renewable energy standard requirements, the Department recommended that Green Mountain Power's savings resulting from its battery storage program not be allowed until the Public Utility Commission provides guidance on whether energy storage savings are allowable under Tier III. At issue is the fact that the avoided fossil fuel-fired electricity generation would not have been within Green Mountain Power's service territory or the state of Vermont. The Commission held a workshop in August 2018 to discuss the eligibility of energy storage projects for Tier III renewable energy standard compliance. Following the workshop, the Commission accepted comments until mid-September on how or whether battery storage used to reduce peak load meets Tier III RES obligations. The Commission approved the utilities' 2017 RES compliance filings in December.	Docket No. 17-4632-INV
WA	AMI Rules	The Utilities and Transportation Commission opened a docket in June 2018 to consider modifying existing consumer protection and rules related to AMI. In its initial filing, the Commission presented a series of questions and requested responses from interested parties by September 2018. In December 2018, the Commission published draft rules, which it is accepting comments on through January 31, 2019. A public comment hearing is scheduled for February 21, 2019, and a workshop is scheduled for March 13, 2019.	Docket No. U-180525

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of late January 2019.

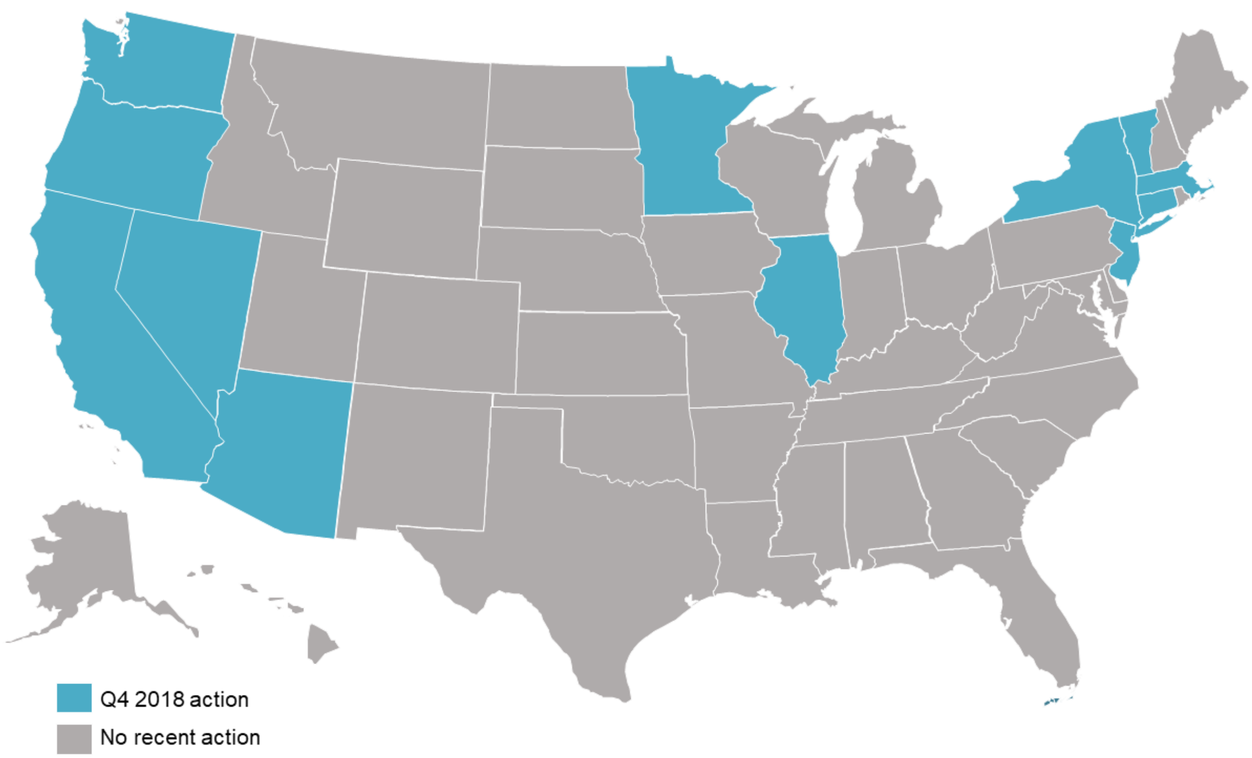
FINANCIAL INCENTIVES

Key Takeaways:

- In Q4 2018, there were 28 actions under consideration in 12 states related to incentives for grid modernization technologies.
- Of these, 19 incentive proposals were for energy storage technologies, while 5 were for microgrids, 4 were for demand response, 2 were for smart inverters, and 1 would apply to grid modernization technologies generally.
- The California Public Utilities Commission approved San Diego Gas & Electric's and Southern California Edison's energy storage incentives for low-income customers.

In Q4 2018, there were 28 actions under consideration in 12 states related to financial incentives for grid modernizing technologies. These actions include tax credits, property and sales tax exemptions, grant programs, rebate programs, loan programs, and property assessed clean energy (PACE) financing programs.

Figure 35. Action on Financial Incentives (Q4 2018)



Six actions created new incentives for grid modernization technologies in Q4 2018. In New York, a bill was enacted providing a 10% property tax abatement for energy storage equipment. New York also announced that solar projects paired with energy storage will be eligible for additional funding through the existing NY-SUN program. The California Public Utilities Commission approved energy storage procurement plans proposed by San Diego Gas &

Electric and Southern California Edison, which include rebates for energy storage equipment for low-income customers and multi-family dwellings. The Illinois Commerce Commission also approved rebates for distributed generation systems using smart inverters.

Box 6. Tax Incentives, Grants, Rebates, and Financing Programs

The term **tax incentives** covers a broad spectrum of incentives, including income **tax credits** and **deductions**; **property tax exemptions**, exclusions, abatements, and credits; and **sales tax exemptions** and refunds. **Performance-based incentives** are based on the energy production of a system. **Grant programs** are one-time monetary payments, typically awarded through a competitive process, while **rebate programs** provide cash incentives for equipment installations meeting program specifications. Finally, **loan programs** provide financing for the purchase of advanced grid technologies and **Property Assessed Clean Energy (PACE) financing** programs allow property owners to borrow money to pay for certain clean energy improvements and repay the amount via a special assessment on the property. Information about incentives for renewable energy and energy efficiency is included in the Database of State Incentives for Renewables and Efficiency.

Several bills under consideration died as most of the remaining state legislative sessions came to a close in Q4 2018. However, several bills relating to grid modernization incentives, and energy storage incentives in particular, have already been introduced in January 2019. Several regulatory proceedings related to incentives will also continue into 2019.

Figure 36. Q4 2018 Action on Incentives by Incentive Type

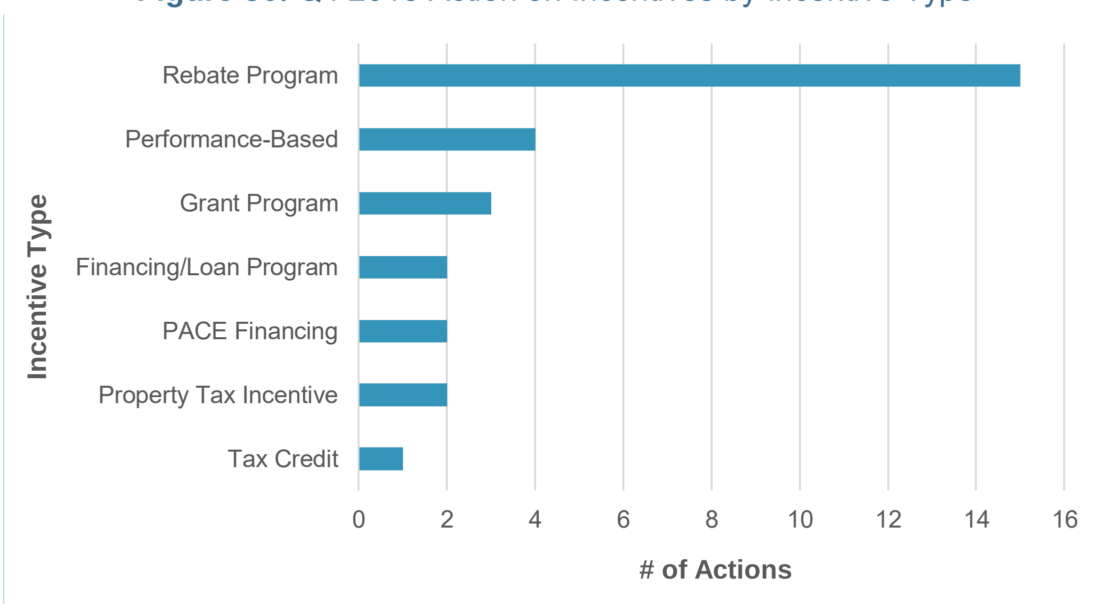


Table 14. Updates on Financial Incentives (Q4 2018)

State	Incentive Type	Description	Source
AZ	Rebate Program	In early September 2017, Arizona Public Service (APS) filed its application for approval of its 2018 demand-side management plan. As part of its plan, APS proposed a pilot incentive program for grid-connected water heating at residential homes. The incentive would equal about $200. APS has also proposed a pilot measure for free water heater timers to control the timing of electric water heating at residential homes and small businesses. Participants must be on a TOU or demand rate. In early July 2018, Commissioner Olson requested that APS submit the Ratepayer Impact Measure and savings during peak for each program.	Docket No. E-01345A-17-0134
CA	Rebate Program	The Self-Generation Incentive Program (SGIP) provides rebates for energy storage systems. In December 2017, the CPUC issued a ruling establishing a working group to develop changes to the SGIP program to reduce greenhouse gas emissions attributable to energy storage. The working group submitted its final report in June 2018. The report presents the findings of the working group after modeling the greenhouse gas reductions of various energy storage scenarios, including residential and commercial systems with and without solar under old rates and new rates that feature a peak period starting at 3pm or later. The report then provides a list of recommendations. A revised report was released in August 2018, and the CPUC accepted comments in September. In November 2018, the utilities filed a Joint Petition for Modification of a prior decision related to the rules for determining eligibility for incentive adders for equipment manufactured in California. On December 31, 2018, the CPUC released a revised SGIP greenhouse gas proposal for comment.	Docket No. R-12-11-005 Decision No. 17-10-004 Decision No. 17-04-017 Working Group Final Report
	Rebate Program	A.B. 2695, introduced in February 2018, increases the budget for the Self-Generation Incentive Program by $140 million, with the additional money reserved for energy storage projects for low and middle income consumers. The bill did not advance during the 2018 legislative session.	A.B. 2695 (D)
	Rebate Program	In February 2018, San Diego Gas & Electric filed for approval of its 2018 Energy Storage and Procurement Plan, which includes an energy storage incentive program for low-income customers. The proposed program, Energy Storage Incentive for Expanded CARE Pilot Program, would provide an incentive of $1.20 per Watt-hour. A prehearing conference was held in May 2018 to discuss the	Docket No. A18-02-016 October 2018 Decision

		applications filed by the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission issued a final decision in October 2018, approving the utilities' procurement plans.	
	Rebate Program	In March 2018, Southern California Edison filed for approval of its 2018 Energy Storage and Procurement Plan, which includes a $9.8 million incentive program for energy storage installations at low-income multifamily dwellings. The proposed incentive would begin at $0.75 per Watt-hour and step down to $0.60 per Watt-hour. Eligible projects would be sized 100 kWh to 1 MWh. A prehearing conference was held in May 2018 to discuss the applications filed by the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission issued a final decision in October 2018, approving the utilities' procurement plans.	Docket No. A18-03-002 October 2018 Decision
CT	Grant Program	The Connecticut Green Bank filed a new Technology Eligibility application under the Connecticut Electric Efficiency Partners (EEP) program in December 2018. The EEP program's primary goal is to reduce peak demand through the use of demand-side technology. The EEP program partners can apply for grants to assist with the implementation of projects. The Green Bank application filed for battery energy storage technology systems (EES) paired with solar PV to be eligible as demand-side management technologies under the EEP program. ESS systems would be installed at residential sites to reduce peak demand as needed throughout the year. ESS will be discharged during ISO-New England summer and winter on-peak hours, and during utility TOU peak hours and charged with solar PV during utility off-peak hours. The Green Bank is seeking to market this technology, and will be providing an incentive from $500/kWh to $325/kWh on a decreasing MW block. Battery storage projects for residential customers are not to receive public funding through the Clean Energy Fund. As part of the Green Bank's application, it requested that certain battery information be kept confidential. In January 2019, the PURA rejected the request for confidential treatment, finding the reasoning inadequate.	Docket No. 18-12-35
IL	Rebate Program	In March 2018, Ameren Illinois filed a proposed tariff for rebate programs for DG projects incorporating "smart inverters," as required by the 2016 Future Energy Jobs Act. The rebate program would not provide additional compensation for utility use of the Volt/VAR function and other services available from smart meters beyond the base rebate amount. In	Docket No. 18-0537 Future Energy Jobs Act

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		September 2018, an administrative law judge issued a proposed order which would approve the proposed tariff, but would require Ameren to record smart inverter usage to assist with a future proceeding, which will address the question of which smart inverter functions are an additional use requiring compensation under the 2016 legislation. In late November 2018, the Commission issued a final order approving Ameren's proposal. In early December 2018, the Attorney General of Illinois filed a petition for rehearing, arguing that Ameren's proposal should be aligned with ComEd's (Docket No. 18-0753) and that both programs should incorporate a non-bypassable volumetric charge to ensure that program participants pay their fair share of costs for the program. On December 19, 2018, the Commission denied the petition for rehearing.	
	Rebate Program	In April 2018, Commonwealth Edison (ComEd) filed a proposed tariff for rebate programs for DG projects incorporating "smart inverters," as required by the 2016 Future Energy Jobs Act. The rebate program would not provide additional compensation for utility use of the Volt/VAR function and other services available from smart meters beyond the base rebate amount. In October 2018, an administrative law judge issued a proposed order, which would approve the proposed tariff, but would require ComEd to record smart inverter usage to assist with a future proceeding which will address the question of which smart inverter functions are an additional use requiring compensation under the 2016 legislation. In late November 2018, the Commission issued a final order approving ComEd's proposal.	Docket No. 18-0753 Future Energy Jobs Act
MA	PACE Financing	H. 2687 and S. 1825 allow microgrids as an eligible measure for commercial property assessed clean energy financing. The bills did not advance during the 2017-2018 legislative session.	H. 2687 (D) S. 1825 (D)
	Performance-Based Incentive	Legislation enacted in April 2016 directed the Department of Energy Resources (DOER) to develop a new solar incentive program to succeed the Solar Renewable Energy Credit II (SREC II) Program. The new program takes the form of a performance-based incentive and includes an adder for solar + storage systems. The base adder is $0.045/kWh and will decrease by 4% with each block of installed solar capacity (amount of capacity per block will vary by utility territory.) This adder will vary based on the ratio of storage capacity to solar capacity, as well as the duration of the storage system. To be eligible, the nominal rated power capacity of the storage system must be at least 25% and the nominal useful energy	Docket No. 17-140 Development of the Next Solar Incentive 225 CMR 20.00 Order Approving Model SMART Provision

		capacity must be at least two hours, although the system will not receive credit for nominal useful energy capacity greater than six hours. The storage system must also have at least 65% roundtrip efficiency, must discharge at least 52 complete cycle equivalents per year, and the owner must be able to provide historical 15-minute interval performance data. In August 2017, DOER filed the final version of the regulation. In September 2017, the state's distribution utilities jointly filed a model SMART tariff. Stakeholders filed testimony and the distribution utilities responded to information requests during Q1 2018. The Department of Public Utilities (DPU) issued a final order in September 2018, approving a SMART program tariff. The final order directs utilities to revise the SMART provision to make it clear that eligible projects installed on a microgrid are eligible for the incentive. In late November 2018, the DPU directed each distribution company to file company-specific SMART provisions for review. The companies filed their SMART tariffs in early December 2018. The DPU requested certain modifications to the tariffs, and the companies refiled their tariffs later in December.	
	Loan, Program, Performance-Based Incentive	In late October 2018, Massachusetts' electric utilities filed their joint statewide electric and gas three-year energy efficiency plan, covering 2019-2021. The proposed plan includes performance-based incentives for customer-owned energy storage. Participating customers with storage systems will receive incentives for dispatching the storage during daily peak hours ($200 per kWh), as well as for dispatching during targeted call events ($100 per kWh). The plan also adds storage to the technologies eligible for the state's HEAT loan program, if the customer is participating in the performance-based incentive program. The Department of Public Utilities approved the targeted dispatch incentive and a demonstration offering of the daily dispatch incentive in January 2019.	Docket No. 18-117 Docket No. 18-118 Docket No. 18-119
MN	Performance-Based Incentive	In December 2018, Minnesota Power filed a petition for approval of several new demand response programs for large industrial customers. The programs include a short-term emergency capacity product offering a $0.60 per kW credit for monthly interruptible billing demand reduction, a long-term emergency capacity product offering a $7 per kW-month credit for up to 150 MW of capacity and a $30 per MWh credit for customers who disrupt operations for economic reasons, and a surplus capacity product for customers with excess capacity that does not fit into other categories.	Docket No. 18-735

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NJ	PACE Financing	S.B. 1611 and A.B. 1902 allow energy storage systems and microgrids to be eligible for property assessed clean energy financing.	S.B. 1611 (I) A.B. 1902 (I)
	Rebate Program	S.B. 599 and A.B. 4009 direct the Board of Public Utilities to establish demand response programs. Utilities are to provide participating customers with a monthly rebate equal to 10% of the customer's monthly bill. Customers are responsible for the purchase and cost of installing any devices required for participation.	S.B. 599 (I) A.B. 4009 (I)
	Rebate Program	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Efficiency Program includes a variety of customer-focused programs, including a Smart Homes Pilot Program focused on providing comprehensive energy solutions to participants. The program covers a wide variety of technologies, including traditional energy efficiency and smart appliances, as well as battery storage, water heaters, connected PV inverters, and electric vehicles. Rebate levels for platforms or individual devices will be set prior to the subprogram launch. The total proposed budget for the Smart Homes Pilot Program is about $26.3 million.	PSE&G Regulatory Filings (Docket No. EO18101113)
	Rebate Program	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Efficiency Program includes a variety of customer-focused programs, including a Non-Wires Alternatives (NWA) Pilot Program, which will seek to defer or replace the need for investment in new electric infrastructure through targeted deployment of DG, energy storage, energy efficiency, demand response, and grid software and controls. PSE&G will conduct an analysis to determine the NWA target zones, and will offer incentives to residential, commercial, and industrial customers in these zones to deploy various NWA technologies. The total proposed budget for the NWA Pilot Program is about $26.3 million.	PSE&G Regulatory Filings (Docket No. EO18101113)
NV	Rebate Program	In October 2018, the Public Utilities Commission of Nevada opened a proceeding to establish a working	Docket No. 18-10022

		group to make recommendations regarding eligibility for NV Energy's large energy storage incentive program, pursuant to the regulations established in Docket No. 17-08021. The working group is to meet at least once per year. Letters of interest for participation in the working group were due by December 28, 2018.	
NY	Financing Program	A.B. 10233 and its companion bill create the Take Charge New York Program, to be administered by the New York Power Authority. Awardees would receive a subsidy to cover the development and infrastructure needed to install and maintain a microgrid at the applicant's place of business. Awardees would then pay back this amount through the value of energy saved. The bills did not advance before the end of the 2017-2018 legislative session.	A.B. 10233 (D) S.B. 7769 (D)
	Grant Program	S.B. 4490 requires the New York State Energy Research and Development Authority to create a grant program to provide incentives up to $150,000 per applicant to promote microgrids in the state. A companion bill, A.B. 9852, was introduced in February 2018. The bills did not advance before the end of the 2017-2018 legislative session.	S.B. 4490 (D) A.B. 9852 (D)
	Property Tax Incentive	S.B. 6762 expands the state's property tax exemption for renewable energy systems to include micro-hydro, fuel cells, combined heat and power, and electric energy storage equipment and systems. The bill passed the Senate in June 2018, but died at the end of the 2017-2018 legislative session.	S.B. 6762 (D) A.B. 8906 (D)
	Property Tax Incentive	A.B. 10410 and its companion bill provide a property tax abatement for energy storage equipment in New York City worth 10% of the expenditures on the equipment (up to a maximum of $6,500 or the total value of taxes owed by the owner of the equipment). The Governor signed the bills into law in December 2018.	A.B. 10410 (E) S.B. 8971 (E)
	Rebate Program	S.B. 8587, introduced in May 2018, creates a rebate program for "resiliency facilities," meaning renewable DG systems capable of operating without grid support, as well as mobile energy storage devices. The bill did not advance before the end of the 2017-2018 legislative session.	S.B. 8587 (D)
	Rebate Program	As part of a joint investment proposal filed in May 2018 by New York State Electric and Gas, Rochester Gas and Electric, the Department of Public Service, the Department of State, the Division of Consumer Protection, and others, the utilities would offer a financial assistance program for back-up power assistance for customers with life-sustaining	Docket No. 17-E-0594/17-00540

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		equipment. The program would cover 50% the cost of qualifying equipment, including battery back-up systems, up to $1,000. The estimated cost of the program is $200,000. The investment proposal is designed to improve grid resiliency and emergency response in the areas impacted by a March 2017 windstorm. Several parties filed statements in support of the proposal in July 2018.	
	Rebate Program	In October 2018, the governor of New York announced that $40 million would be made available through the state's NY-SUN program for solar projects paired with energy storage. NY-SUN's 2018-2023 operating plan, released on October 19, 2018, explains that the funding will be provided as adders to the rebates provided by NY-SUN to nonresidential and commercial/industrial solar projects, although the additional incentive amount for incorporating energy storage was not specified.	Docket No. 14-00549/14M-0094 Press Release
	Tax Credit	A.B. 6235 creates a state tax credit for residential energy storage systems equal to 25% of costs, up to $7,000. The bill did not advance before the end of the 2017-2018 legislative session.	A.B. 6235 (D)
OR	Rebate Program	In August 2018, Portland General Electric filed for approval to extend the deadline for its Residential Demand Response Water Heater Pilot to March 31, 2019. PGE will provide a $50 sign-up incentive to participating customers, plus $100 to customers who participate for a full year. In September 2018, the Commission Staff recommended approval of the pilot extension.	Docket No. ADV 822
VT	Performance-Based Incentive	In December 2018, Green Mountain Power filed a letter notifying the Commission that it plans to open its Flexible Load Management and Thermal Energy Storage Innovative Pilot on December 23, 2018. The pilot focuses on using ice storage resources at commercial and industrial customer sites with flexible loads. The utility will provide a credit for peak reduction (sharing 70% of the value with the host customers).	Docket No. 18A-4147
WA	Grant Program	In December 2018, Governor Inslee released a clean energy proposal, which includes $22.5 million for grid modernization grants over 2019-2021. The proposal also includes a variety of investments in renewable energy, electric vehicle infrastructure, and building efficiency.	Proposal

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of late January 2019.

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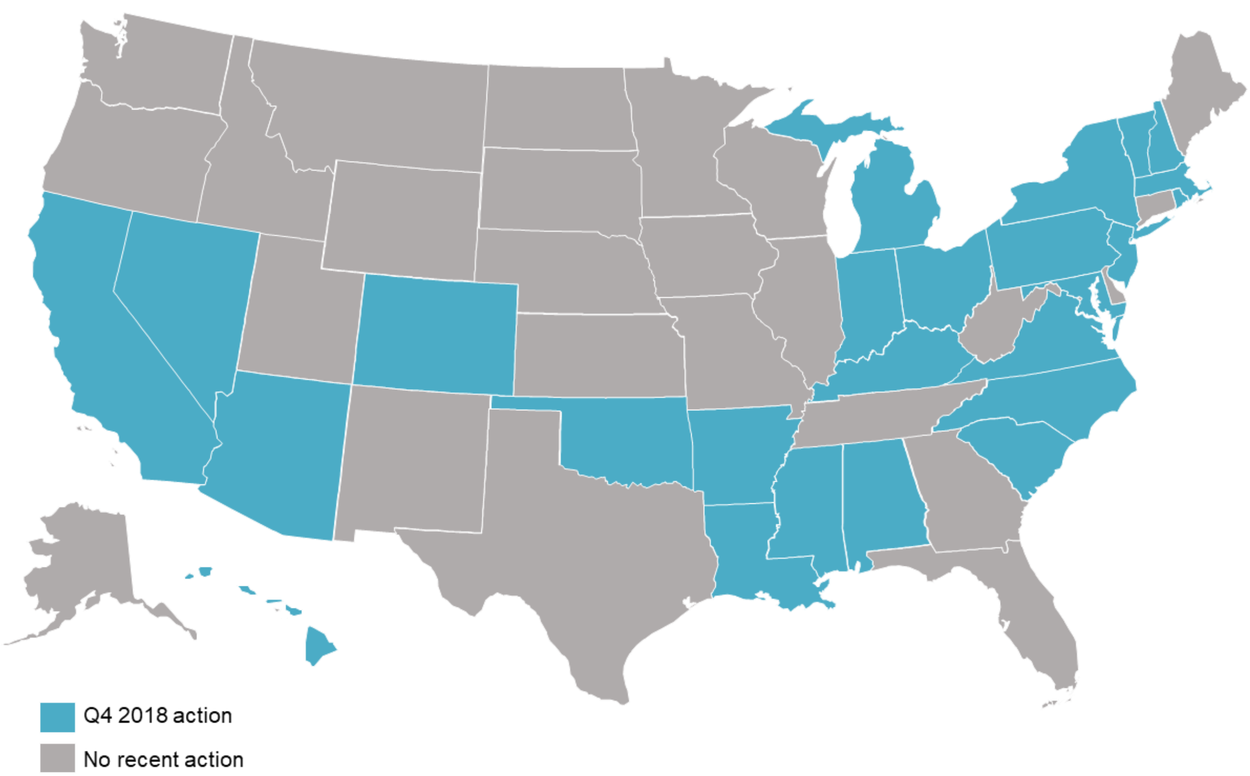
DEPLOYMENT OF GRID MODERNIZING TECHNOLOGIES

Key Takeaways:

- In Q4 2018, there were 52 pending or decided proposals from state legislators or utilities across 25 states to deploy grid modernizing technologies, such as advanced metering infrastructure (AMI), smart grid components, microgrids, and energy storage.
- The majority of actions related to proposals to deploy energy storage projects, with 30 requests under consideration during the quarter.
- Utilities in five states – Arkansas, Massachusetts, Ohio, South Carolina, and Virginia – proposed new smart grid investments in Q4 2018.

Utilities continue to request approval and cost recovery for the deployment of grid modernizing technologies. In Q4 2018, there were 52 legislative or utility deployment proposals under consideration in 25 states. Of these requests, the majority related to energy storage projects, followed by smart grid or distribution system modernization investments.

Figure 37. Action on Grid Modernization Technology Deployment (Q4 2018)



Advanced Metering Infrastructure

There were 15 open proceedings under consideration in 9 states related to the AMI deployment. Dayton Power & Light in Ohio, Duke Energy Carolinas and Duke Energy Progress in South

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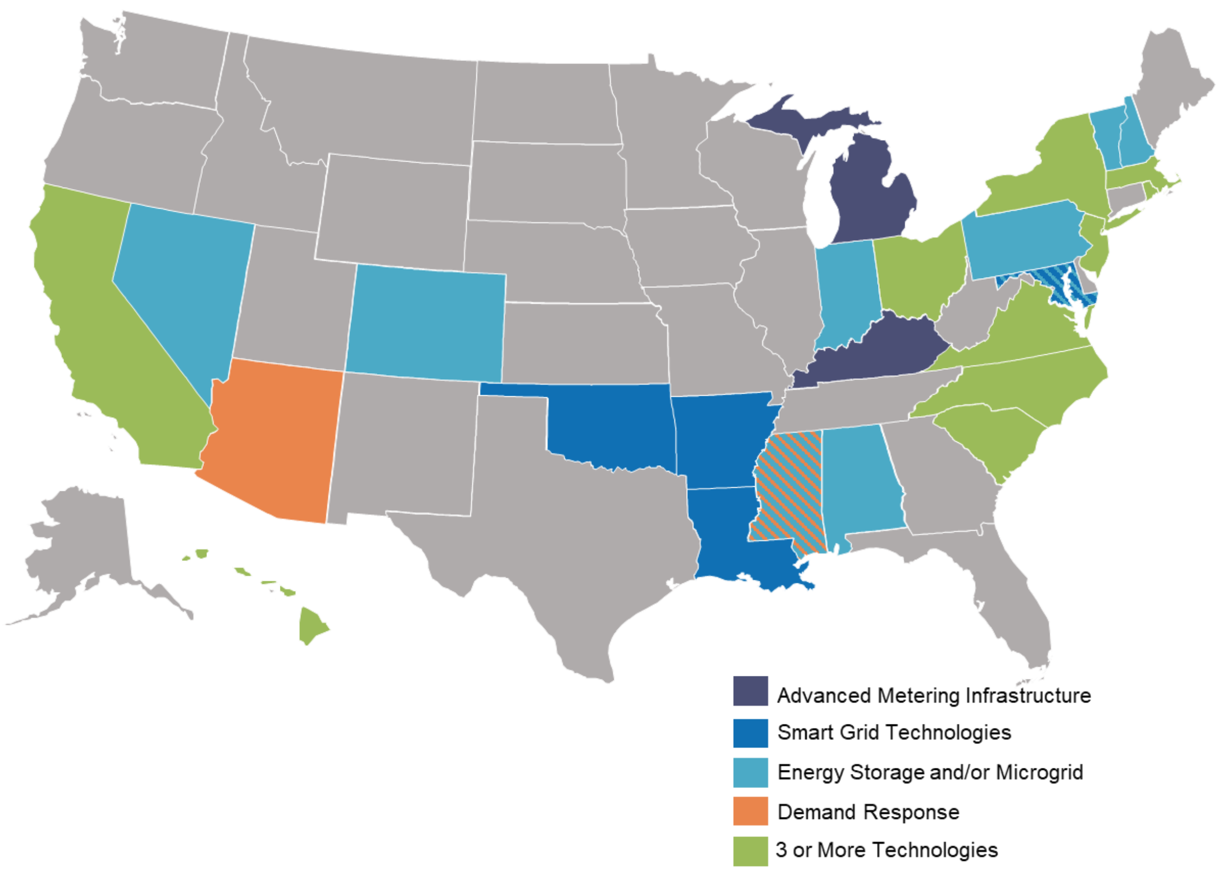
Carolina, and Appalachian Power in Virginia filed new requests to deploy AMI in Q4 2018. AMI deployment requests also remain under consideration in Hawaii, Michigan, New Jersey, and Ohio. Kentucky regulators approved cost recovery for $23.4 million in AMI investment for Duke Energy during the quarter, while Virginia regulators denied Dominion Energy's AMI proposal in January 2019.

Figure 38. Proposed Deployments by Technology Type (Q4 2018)



Smart Grid / Distribution System Modernization

There were 21 open proceedings under consideration in 13 states related to smart grid technology deployment or distribution system modernization. New smart grid deployment proposals were filed by utilities in five states in Q4 2018 – Arkansas, Massachusetts, Ohio, South Carolina, and Virginia. National Grid's proposal in Massachusetts is relatively small, focusing on IT modernization; however, the utility also proposed energy storage and electric vehicle investments.

Plans filed by Dayton Power & Light (OH), Duke Energy Carolinas and Duke Energy Progress (SC), and Appalachian Power (VA) were much more significant, with proposed investments ranging from $455 million to $587 million. No smart grid or distribution system deployment plans were approved or denied during Q4 2018; Dominion Energy's petition in Virginia for approval of the first phase of its Grid Transformation Plan was partially approved and partially denied in January 2019.

Energy Storage

There were 30 open proceedings or bills under consideration in 15 states related to energy storage deployment. Energy storage procurement plans from California's three major investor-owned utilities were approved this quarter. A pilot energy storage program proposed by Duke Energy Ohio was also approved, and Virginia issued guidelines for energy storage pilot programs to be deployed by Appalachian Power and Dominion Energy. A microgrid and energy storage proposal by Duquesne Light Company in Pennsylvania was withdrawn.

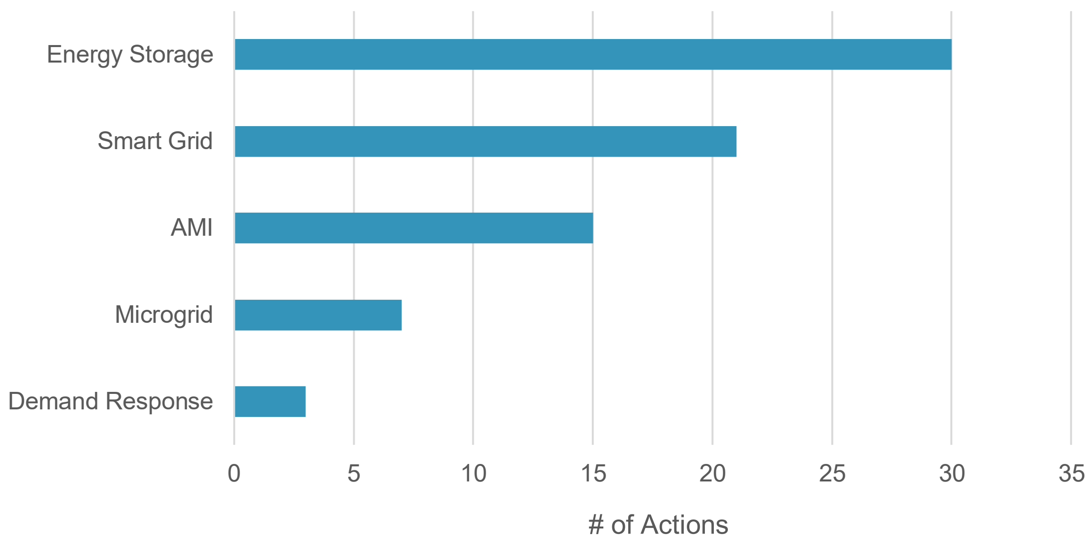
Table 15. Proposed AMI and Smart Grid Investments (Q4 2018)

State	Utility	Proposed Budget	Approved Budget
Arkansas	Oklahoma Gas & Electric	$20 Million	Pending
California	Southern California Edison	$2.1 Billion	Pending
Hawaii	HECO, HELCO, MECO	$86.3 Million	Pending
Kentucky	Duke Energy Kentucky	$23.4 Million	$23.4 Million
Louisiana	Entergy New Orleans	$59.3 Million	Pending
Maryland	Potomac Edison	$10.7 Million	Pending
Michigan	Upper Peninsula Power Co.	$15.6 Million	Pending
New Jersey	Atlantic City Electric	$338.2 Million	Pending
New Jersey	Jersey Central Power & Light	$386.8 Million	Pending
New Jersey	PSE&G New Jersey	$810.3 Million	Pending
New York	PSEG Long Island	$204 Million	Pending
Ohio	Dayton Power & Light	$866.9 Million	Pending
Ohio	First Energy	$450 Million	Pending
Ohio	First Energy	$600 Million	Pending
Oklahoma	Public Service Co. of Oklahoma	$175 Million	Pending
South Carolina	Duke Energy Carolinas, Duke Energy Progress	$455 Million	Pending
Virginia	Appalachian Power	$587.4 Million	Pending
Virginia	Dominion Energy	$1.49 Billion	$154.5 million (Jan. 2019)
TOTAL		$8.68 Billion	$177.9 Million

Microgrids

There were seven open proceedings or bills under consideration in five states related to deployment of microgrids, including pilot projects aimed at learning more about microgrid capabilities and benefits. The Public Utilities Commission of Ohio approved Duke Energy's proposed microgrid project, and Pennsylvania regulators issued an order approving a settlement that withdraws a microgrid project proposal from Duquesne Light Company. Duke Energy Progress in North Carolina filed a request for approval of a new microgrid in Q4 2018.

Figure 39. Proposed Deployments by Technology Type (Q4 2018)



Demand Response

There were three open proceedings related to demand response deployment in three states during Q4 2018. Arizona Public Service's "reverse demand response" program, proposed as part of its Demand-Side Management Program, remains under consideration, as does Entergy Mississippi's new program offering various DERs, including demand response, to customers.

Table 16. Updates on Grid Modernization Technology Deployment (Q4 2018)

State	Utility	Technology	Description	Source
AL	Alabama Power	Energy Storage	Alabama Power issued an RFP for firm capacity in October 2018. The utility considered proposals for projects from 100 to 1,200 MW, and explicitly stated that energy storage and resources combined with energy storage are eligible to bid into the RFP. Proposals were accepted until November 9, 2018.	Alabama Power Capacity RFP
AR	Oklahoma Gas & Electric	Smart Grid	In October 2018, Oklahoma Gas & Electric filed its formula rate plan application, including a request for approval of certain grid modernization investments totaling $20 million. The proposed investment breaks down to 46% structural integrity, 16% functional integrity, and 38% grid technology enhancements and will focus on 14 circuits. New technology being deployed includes automated reclosers and switches. A public evidentiary hearing is scheduled for February 2019.	Docket No. 18-046-FR
AZ	Arizona Public Service	Reverse Demand Response	In early September 2017, Arizona Public Service (APS) filed its application for approval of its 2018 demand-side management plan. As part of its plan, APS proposed a new "reverse demand response" pilot program for non-residential customers with demand of at least 30 kW. This program would identify opportunities to dispatch loads in response to negative pricing events. Participation is limited to non-essential loads, which would receive no-cost energy during specified time periods. The proposed program would be limited to $200,000, and APS would deploy necessary sub-metering and communications infrastructure. In early July 2018, Commissioner Olson requested that APS submit the Ratepayer Impact Measure and savings during peak for each program.	Docket No. E-01345A-17-0134
CA	Southern California Edison	Demand Response, Energy Storage	In July 2018, the California Public Utilities Commission issued a decision approving the results of Southern California Edison's (SCE) Second Preferred Resources Pilot Request for Offers. SCE requested approval to enter into 19 purchase and sale agreements for 125 MW of preferred resources. This includes 60 MW of front-	Docket No. A-16-11-002 Decision No. 18-07-023

		of-the-meter energy storage, 55 MW of demand response, and 10 MW of behind-the-meter solar paired with energy storage. In August 2018, the Office of Ratepayer Advocates filed a request for rehearing, which the Commission denied in December 2018.	
Liberty Utilities	Energy Storage	Liberty Utilities filed an application in November 2017 for approval of a 2.6 MW / 15 MWh battery storage system. The main goals of the project are to improve the quality of electricity to its customers, improve system reliability, and improve safety. The total cost is estimated to be $8.4 million. Liberty Utilities filed a brief in support of its proposal during Q3 2018. An ALJ filed a ruling in November 2018, directing Liberty Utilities to file supplemental testimony by December 10, 2018. The ruling includes 12 specific questions related to the proposed project, the reliability issues the utility is seeking to address with the project, and the bidding process the utility went through to select a vendor.	Docket No. A-17-11-014
Pacific Gas & Electric	Energy Storage	In March 2018, Pacific Gas & Electric filed for approval of its 2018 Energy Storage and Procurement Plan, which includes the deployment of 166 MW of energy storage. Like its previous Energy Storage Procurement Plans, Pacific Gas & Electric plans to reach its deployment target though requests for offers. A prehearing conference was held in May 2018 to discuss the applications filed by all of the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a proposed decision in September 2018, which approves the utilities' procurement plans. A final decision approving the procurement plans was issued in October 2018.	Docket No. A18-03-001 October 2018 Decision
Pacific Gas & Electric, Southern California Edison	Energy Storage	In December 2017, Pacific Gas & Electric filed for approval of six energy storage agreements resulting from its 2016-2017 Request for Offers. The projects total 165 MW of energy storage capacity. Southern California Edison also filed an application for 10 MW of battery storage. Both utilities proposed to recover costs through their respective Energy Resource Recovery	Docket No. A17-12-003

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		Accounts. A decision issued in October 2018 approves the energy storage agreements and cost recovery mechanisms. The Public Advocates Office filed an application for rehearing of the decision in November 2018, citing issues with one of the projects proposed by PG&E. On December 4, 2018, PG&E and the California Energy Storage Alliance filed responses citing their opposition to the Public Advocates Office's Application for Rehearing.	
San Diego Gas & Electric	Energy Storage	In February 2018, San Diego Gas & Electric filed for approval of its 2018 Energy Storage and Procurement Plan, which includes the deployment of 166 MW of energy storage. A prehearing conference was held in May 2018 to discuss the applications filed by all of the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a proposed decision in September 2018, which approves the utilities' procurement plans. A final decision approving the procurement plans was issued in October 2018.	Docket No. A18-02-016 October 2018 Decision
Southern California Edison	Energy Storage	In March 2018, Southern California Edison filed for approval of its 2018 Energy Storage and Procurement Plan, which includes the procurement of a minimum of 20 MW of energy storage. Specifically, the proposal includes a solicitation for approximately 40 MW of utility-owned energy storage and a $9.8 million incentive program for energy storage installations at low-income multifamily dwellings. A prehearing conference was held in May 2018 to discuss the applications filed by all of the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a proposed decision in September 2018, which approves the utilities' procurement plans. A final decision approving the procurement plans was issued in October 2018.	Docket No. A18-03-002 October 2018 Decision
Southern California Edison	Smart Grid	In its latest rate case, Southern California Edison proposed an investment of $2.1 billion in capital expenditures from 2016 - 2020 for its Grid Modernization plan,	Docket No. A-16-09-001

			which includes structural upgrades, automation for real-time monitoring and control, new telecommunications capabilities, and new software for system management. An evidentiary hearing was held in March 2018, and a May 2018 decision extended the statutory deadline for the proceeding to December 3, 2018. A decision issued on December 6, 2018 again extended the statutory deadline, now set at June 3, 2019.	Southern California Edison Proposal
CO	Public Service Company of Colorado d/b/a Xcel Energy	Energy Storage	In June 2018, Public Service Company of Colorado d/b/a Xcel Energy filed a Colorado Energy Plan (CEP) Portfolio as part of Phase 2 of its Electric Resource Plan. The CEP Portfolio includes 275 MW of battery storage, all paired with solar projects. In September 2018, the Public Utilities Commission issued a decision approving the resource selection in the CEP Portfolio.	Docket No. 16A-0396E
HI	Hawaiian Electric Companies	AMI, Smart Grid	In June 2018, the HECO Companies filed an application for Phase 1 of its grid modernization project, spanning 2019 - 2023 at a total estimated cost of approximately $86.3 million. Phase 1 includes the deployment of advanced meters, a meter data management system, and a telecommunications network. The forecasted AMI deployment during Phase 1 is over 175,000 meters, and will be deployed during the routine replacement of meters, the installation of new meters, and for customers participating in one of the utilities' DG tariffs. The Division of Consumer Advocacy filed a Statement of Position in November 2018 citing concerns with the application but ultimately recommending it subject to multiple conditions based on the urgent need to begin smart meter deployment. In December 2018, the HECO companies submitted a reply statement in response to the Division's Statement of Position, defending the companies' proposal.	Docket No. 2018-0141 Phase I Grid Modernization Strategy
	Hawaiian Electric Companies	Energy Storage	In May 2018, the HECO Companies filed an application for a 20 MW battery capable of storing 80 MWh of energy at the West Loch Naval Annex, the site of a planned grid-scale PV project. Construction on the project is scheduled	Docket No. 2018-0102

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			to start in October 2019 with the unit placed in service in February 2020. The total estimated cost is $43.5 million. The Companies proposed recovering the project's costs through the Major Project Interim Recovery Mechanism. An ultimate decision is expected in April 2019.	
	Hawaiian Electric Companies	Energy Storage	In May 2018, the HECO Companies filed an application for a 100 MW battery energy storage system capable of storing 100 MWh of energy at Hawaiian Electric's Campbell Industrial Park Generating Station. Construction on the project is scheduled to start in October 2019 with an in-service date of October 2020, at a total estimated cost of $104 million. The Companies proposed recovering the project's costs through the Major Project Interim Recovery Mechanism. An ultimate decision is expected in April 2019.	Docket No. 2018-0103
IN	Northern Indiana Public Service Company	Energy Storage	In October 2018, Northern Indiana Public Service Company (NIPSCO) presented its 2018 integrated resource plan. The utility's preferred plan includes 1,150 MW of solar and storage by 2023. The utility would conduct an all-source RFP, which it anticipates would likely lead to renewables and storage being deployed.	NIPSCO IRP Presentation
KY	Duke Energy Kentucky	AMI	In September 2017, Duke Energy Kentucky filed for a general rate increase. The rate increase includes cost recovery for AMI installation with a proposed budget of $23.4 million. In an April 2018 order, the Public Service Commission denied Duke's requested rate increases, but approved alternative rate increases set out in the order. The order did not allow cost recovery for AMI. In May 2018, the Commission partially approved requests for rehearing on several issues, and cost recovery for AMI is an issue being reconsidered. In early October 2018, the Commission issued a final order, approving cost recovery for AMI.	Docket No. 2017-00321 Order (May 2018) Order (October 2018)
LA	Entergy New Orleans	Smart Grid	In Entergy New Orleans' general rate case filed in September 2018, the utility requested cost recovery for five grid modernization projects. The five projects include installation of 40 self-healing network areas, 545 smart devices, and	City Council Docket No. 18-07

			109.8 line miles of new conductor. The total estimated cost of the projects is $59.3 million. Entergy proposed recovering portions of the projects closing before December 31, 2019 through base rates and the remainder through a new Distribution Grid Modernization Rider (Rider DGM). Future grid modernization projects would also be recovered through Rider DGM. Entergy also proposed a process for the review of new grid modernization projects, including a six-month timeframe.	
MA	Cape Light Compact	Energy Storage	In late October 2018, Massachusetts' electric utilities filed their joint statewide electric and gas three-year energy efficiency plan, covering 2019-2021. As part of the plan, Cape Light Compact proposed an Enhanced Storage Incentive program, where the Compact would install 1,000 behind-the-meter battery storage systems at residential and small commercial buildings. The Compact would provide a 100% incentive for the batteries in exchange for dispatch rights over the warrantied life of the batteries. The Compact would dispatch the batteries on a daily basis during the summer and on a targeted basis during the winter. In January 2019, the Department of Public Utilities issued an order on the plan, rejecting the Compact's proposed energy storage program.	Docket No. 18-116
	Eversource	Energy Storage, Smart Grid	In accordance with the Department of Public Utilities' (DPU) June 2014 order on grid modernization plans, Eversource filed its grid modernization plan in August 2015. Eversource has proposed investments in advanced sensing technology, next generation remote faulted circuit indication, a distribution management system, network load flow, predictive outage detection, automated feeder reconfiguration, voltage optimization, integrated planning tracking for DERs, energy storage, adaptive protection/two-way power flow, resiliency improvements, opt-in time-varying rates and related infrastructure, cybersecurity, communications, and a customer education and outreach plan. The DPU issued an order in May 2018, denying the distribution utilities' AMI deployment	Docket No. 15-122

		proposals, finding that statewide deployment of AMI could result in stranded costs of $210 million, due to the current widespread deployment of AMR meters. The DPU notes that it believes AMI is still necessary to achieve its grid modernization objectives and that it will work with stakeholders to determine the best way to cost-effectively deploy AMI. The DPU will work to evaluate whether targeted AMI deployment to certain customer groups, such as new net metering or electric vehicle customers, is cost-effective. The order reduces the time period for preauthorization of grid modernization investments from five years to three years, with the distribution utilities being required to file three-year short term investment plans rather than five-year plans going forward. The order also reduces the time period for the utilities' strategic grid modernization plans from ten years to five years. The utilities are also to integrate cybersecurity concerns related to grid modernization into their existing planning processes. The DPU approved a three-year budget of $133 million for Eversource, which includes investments in distribution management systems, advanced load flow analysis, VVO, overhead and underground automated feeder reconfiguration, advanced sensing, and communications. The DPU did not preauthorize investment in remote circuit fault indicators for Eversource and did not approve its proposed research and development projects. The DPU approved a short-term targeted cost recovery mechanism for the grid modernization investments (Grid Modernization Factor), which will include both capital investments and incremental O&M investments. The DPU also determined that approved grid modernization costs will be recovered through a volumetric rate. Within 90 days of the order, the companies are to file a joint proposed evaluation plan for the three-year investment term. The next grid modernization filings, including both three-year investment plans and five-year strategic plans, will be due by July 1, 2020. In August 2018, the utilities filed a model Grid Modernization Factor tariff and performance metrics. The utilities also	

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		issued an RFP for a consultant to work with the Department of Energy Resources and the utilities to develop a plan for evaluating the utilities' grid modernization plans. A technical conference on performance metrics is scheduled for February 2019. A joint technical conference on performance metrics is scheduled for February 2019. A joint technical conference related to cost recovery for grid modernization investments, the SMART program, and electric vehicle program costs was held in December 2018.	
Fitchburg Gas and Electric Light Company d/b/a Unitil	AMI, Smart Grid	In accordance with the Department of Public Utilities' June 2014 order on grid modernization plans, Unitil filed its grid modernization plan in August 2015. Unitil's proposed plan includes five programs: (1) DER enablement, (2) grid reliability, (3) distribution automation, (4) customer empowerment, and (5) workforce and asset management encompassing 16 capital investment projects. The DPU issued an order in May 2018, denying the distribution utilities' AMI deployment proposals, finding that statewide deployment of AMI could result in stranded costs of $210 million, due to the current widespread deployment of AMR meters. The DPU notes that it believes AMI is still necessary to achieve its grid modernization objectives and that it will work with stakeholders to determine the best way to cost-effectively deploy AMI. The DPU will work to evaluate whether targeted AMI deployment to certain customer groups, such as new net metering or electric vehicle customers, is cost-effective. The order reduces the time period for preauthorization of grid modernization investments from five years to three years, with the distribution utilities being required to file three-year short term investment plans rather than five-year plans going forward. The order also reduces the time period for the utilities' strategic grid modernization plans from ten years to five years. The utilities are also to integrate cybersecurity concerns related to grid modernization into their existing planning processes. The DPU approved a three-year budget of $4.4 million for Unitil, which includes	Docket No. 15-121

		investments in an enterprise mobile damage assessment tool, outage management system integration with AMI, a field area network, VVO, SCADA, an advanced distribution management system, and a DER analytics visualization platform. The DPU did not preauthorize investments in Unitil's workforce mobility tool or 3V0 deployment. The DPU also did not approve Unitil's proposed research and development projects. The DPU approved a short-term targeted cost recovery mechanism for the grid modernization investments, which will include both capital investments and incremental O&M investments. The DPU also determined that approved grid modernization costs will be recovered through a volumetric rate. Within 90 days of the order, the companies are to file a joint proposed evaluation plan for the three-year investment term. The next grid modernization filings, including both three-year investmente plans and five-year strategic plans, will be due by July 1, 2020. In August 2018, the utilities filed a model Grid Modernization Factor tariff and performance metrics. The utilities also issued an RFP for a consultant to work with the Department of Energy Resources and the utilities to develop a plan for evaluating the utilities' grid modernization plans. A technical conference on performance metrics is scheduled for February 2019. A joint technical conference on performance metrics is scheduled for February 2019. A joint technical conference related to cost recovery for grid modernization investments, the SMART program, and electric vehicle program costs was held in December 2018.	
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	AMI, Smart Grid	In accordance with the Department of Public Utilities' June 2014 order on grid modernization plans, National Grid filed its grid modernization plan in August 2015. National Grid proposed four different scenarios (Balanced Plan Scenario, AMI-Focused Scenario, Grid-Focused Scenario, and Opt-In Scenario) which provide a different portfolio of investments. The plans include investments in the following: AMI, customer load management devices, voltage	Docket No. 15-120

		optimization and conservation voltage reduction technologies, advanced distribution automation, feeder monitors, an advanced communications network, an advanced distribution management system and distribution supervisory control and data acquisition system, information and operational technologies, cybersecurity infrastructure and protocol development, training and asset management, and marketing outreach and education surrounding these technologies and new proposed offerings. The DPU issued an order in May 2018, denying the distribution utilities' AMI deployment proposals, finding that statewide deployment of AMI could result in stranded costs of $210 million, due to the current widespread deployment of AMR meters. The DPU notes that it believes AMI is still necessary to achieve its grid modernization objectives and that it will work with stakeholders to determine the best way to cost-effectively deploy AMI. The DPU will work to evaluate whether targeted AMI deployment to certain customer groups, such as new net metering or electric vehicle customers, is cost-effective. The order reduces the time period for preauthorization of grid modernization investments from five years to three years, with the distribution utilities being required to file three-year short term investment plans rather than five-year plans going forward. The order also reduces the time period for the utilities' strategic grid modernization plans from ten years to five years. The utilities are also to integrate cybersecurity concerns related to grid modernization into their existing planning processes. The DPU approved a three-year budget of $82 million for National Grid, which includes investments in VVO, advanced distribution automation, feeder monitors, communications and information/operational technologies, and advanced distribution management systems/SCADA. The DPU did not approve the company's proposed research and development projects. The DPU approved a short-term targeted cost recovery mechanism for the grid modernization investments, which will include both capital investments and	

		incremental O&M investments. The DPU also determined that approved grid modernization costs will be recovered through a volumetric rate. Within 90 days of the order, the companies are to file a joint proposed evaluation plan for the three-year investment term. The next grid modernization filings, including both three-year investment plans and five-year strategic plans, will be due by July 1, 2020.In August 2018, the utilities filed a model Grid Modernization Factor tariff and performance metrics. The utilities also issued an RFP for a consultant to work with the Department of Energy Resources and the utilities to develop a plan for evaluating the utilities' grid modernization plans. A technical conference on performance metrics is scheduled for February 2019. A joint technical conference on performance metrics is scheduled for February 2019. A joint technical conference related to cost recovery for grid modernization investments, the SMART program, and electric vehicle program costs was held in December 2018.	
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	Energy Storage, Smart Grid	In November 2018, National Grid filed a general rate case, which includes a proposed Phase II Electric Vehicle Market Development Program and an Energy Storage Program. The storage program would deploy up to 14 MW / 56 MWh of energy storage demonstration projects over five years to demonstrate the value of storage for solving distribution needs, improving system performance during peak usage periods, integrating renewable energy, and improving service quality. The proposed budget for the energy storage program is $50 million and National Grid would recover the costs through its Grid Modernization Recovery Provision. The utility also requested cost recovery for several IT projects, including technology modernization and cybersecurity. The proposed IT Technology Modernization Program involves modernizing critical applications to deliver new capabilities and updating operational technology networks to enable distribution automation, monitoring, and metering. Public hearings are scheduled for March 2019.	Docket No. 18-150

MD	Potomac Edison	Smart Grid	In its most recent rate case, filed in August 2018, Potomac Edison proposed investments in distribution automation equipment. The proposed budget for the new investments is approximately $10.7 million, which would be recovered through a new Electric Distribution Investment Surcharge. The Commission established a procedural schedule in October 2018. Multiple parties, including the Office of People's Counsel (OPC), provided testimony in November 2018. On December 6th, the OPC filed revised testimony, which Potomac Edison objected to in a December 10, 2018 motion. In its motion, Potomac Edison argued that the OPC's revised testimony was filed after the deadline and included substantive revisions. The motion calls on the Commission to strike the OPC's revisions and asked for an expedited review of the motion. In December 2018, the Public Service Commission (PSC) denied Potomac Edison's motion to strike the OPC's revised testimony, as the PSC determined the revisions did not present new substantive positions but provide corrections.	Docket No. 9490
MI	Upper Peninsula Power Company (UPPCO)	AMI	In September 2018, as part of a general rate case, UPPCO proposed the deployment of advanced meters to all residential and small commercial customers in its service territory. The investment would total $15.6 million over 2018 and 2019. Initial testimony is due by February 21, 2019, and a final order is expected in August 2019.	Docket No. U-20276
MS	Entergy Mississippi	Demand Response, Energy Storage	In July 2018, Entergy Mississippi proposed a new Smart Energy Services program. Smart Energy Services is intended to broadly encompass energy efficiency and demand response, distributed solar, community solar, battery storage, distributed back-up generation, home energy services, and new billing options. Under the proposed program, Entergy would offer these various services to customers and recover costs in the manner it recovers supply-side resource investments. Entergy notes that one of the major drivers behind its proposed program is to expand access to these types of services to low-income customers.	Docket No. 2018-UA-133

			Entergy filed supplemental testimony in November 2018.	
NC	Duke Energy	Energy Storage	In October 2018, Duke Energy announced that it plans to invest $500 million in battery storage (about 300 MW) in the Carolinas over the next 15 years. The planned investment was included as part of the utility's integrated resource plan.	Press Release
	Duke Energy Progress	Energy Storage, Microgrid	In October 2018, Duke Energy Progress filed an application for a Certificate of Public Convenience and Necessity for its Hot Springs Microgrid Solar and Battery Storage Facility. The project would include 4 MW of lithium-based battery storage facilities. The cost estimate for the project has been redacted from the filing. As the Commission did not receive any significant protest regarding the project, it canceled the public witness hearing scheduled for January 23, 2019.	Docket No. E-2 Sub 1185
	Duke Energy Carolinas	Smart Grid	In Duke Energy Carolinas' latest general rate case, filed in August 2017, the utility requested cost recovery for certain grid investments as part of its 10-year, $13 billion Power/Forward Carolinas plan. These investments include AMI, a distribution management system, automated switches, and communications network upgrades. Across Duke Energy Carolinas and Duke Energy Progress, these four investment categories are expected to total approximately $2.4 billion. The North Carolina Utilities Commission (NCUC) heard testimony over numerous days during March 2018, and a technical workshop was held in May 2018 to discuss the Power/Forward plan with stakeholders. Duke Energy entered a Stipulation and Settlement Agreement with multiple parties in June 2018. Under the proposed settlement, Duke would institute integrated system operation planning, install voltage optimization equipment, invest in electric vehicle charging infrastructure, increase customer data accessibility, and deploy 200 MW of energy storage by May 2023 and another 100 MW by May 2026. A June NCUC order approved many elements of the general rate case, but left open many issues related Power/Forward.	Docket No. E-7 Sub 1146 Power/Forward Carolinas Stipulation Final Order

			The order denied Duke's request for a new Grid Rider, and also asserted that this rate case is not the appropriate place to evaluate the prudency of the company's Power/Forward investments. Existing dockets (such as Integrated Resource Planning and Smart Grid Technology Plans), as well as future general rate case proceedings, will provide opportunities for the Commission to consider Power/Forward. However, since Duke did not propose to recover AMI costs through the Grid Rider, the order approved Duke's request to recover $90.9 million for AMI deployment. The order did not approve the proposed settlement agreement, as this also included the Grid Rider. A technical workshop regarding Duke Energy's revised grid investment plan (Grid Improvement Plan) was held on November 8, 2018. In December 2018, Duke filed a report on plans for AMI and customer connect-enabled rate design, pursuant to the Commission's June order. The report notes that Duke will evaluate a redesigned residential TOU rate, a residential fixed bill rate, a residential variable peak pricing rate, small commercial TOU and variable peak pricing rates, and large commercial/industrial TOU and variable peak pricing rates. Duke noted that it will file at least two pilots (one for residential customers and one for general service customers) at the time of its next rate case. In January 2019, Duke filed a report summarizing the November 2018 workshop on its Grid Improvement Plan, detailing stakeholder feedback. The new plan has a budget of approximately $2 billion.	
NH	Liberty Utilities	Energy Storage	In December 2017, Liberty Utilities filed an application to implement a battery storage pilot program, in which the utility will deploy 5 MW total of battery storage equipment at the homes of 1,000 residential customers. Participating customers would have control over the battery systems, except when a peak demand is predicted for the next day. The goal of the program is to reduce transmission costs and study potential benefits. The utility proposed inclusion of the battery costs in its rate base and	Docket No. 17-189

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		applying a monthly charge to participating customers' bills. The utility is also requesting approval for a TOU rate for program participants, which includes critical peak, on-peak, and off-peak periods. Parties filed testimony in May 2018. The Commission Staff expressed concern about the program's cost-effectiveness and recommended that the program as proposed not be approved. Instead, the Staff recommended that the utility develop a smaller-scale program and work to develop and test a methodology for forecasting ISO-New England system peaks and feeder violations before implementing the program. The Office of the Consumer Advocate is generally supportive of the overall program, but proposed several changes, including: (1) issuing a request for information for third party support with customer education, (2) monetizing the federal investment tax credit for solar customers who would be charging the battery with solar energy, (3) increasing the upfront and monthly fees for participants, (4) requiring the utility to solicit a time-varying supply rate option in its next default service solicitation, (5) having the utility be both exposed to financial upside and downside risk, (6) doing some targeted efficiency upgrades for the non-wires alternative pilot, as well as targeting community centers for resilience benefits, (7) evaluating the program in the same manner as efficiency programs, and (8) opening a statewide docket to design a third-party battery and tariff program. Several other parties generally expressed support for the program as a pilot, but concern about utility ownership of the batteries limiting competition and the proposed TOU rate not being more broadly available. A settlement agreement was filed in November 2018, which approves the program with modifications. Under the settlement, Liberty Utilities can deploy up to 500 Tesla PowerWall 2 batteries on customers' premises, with between 100 and 200 of these being in Phase I of the program. A working group will be established to develop a "Bring Your Own Device" program to deploy 500 additional batteries deployed by third parties.	

			Customers will be able to have a battery installed for either an upfron payment of $2,433 or a monthly payment of $25 for 10 years. Net metering customers will not be able to charge their batteries from the grid, except when the batteries are under Liberty's control, but will receive credit for all energy exported to the grid, including that from the batteries. A hearing on the settlement was held in late November 2018. Sunrun and Revision Energy filed a closing statement in December, explaining their reasons for not signing onto the settlement agreement, but supporting Commission approval of it. In January 2019, the Commission issued an order approving the battery storage program as detailed in the settlement agreement. Before Phase I of the program may be implemented, Liberty Utilities must conduct a comprehensive evaluation of cybersecurity risks associated with the program. The order also directs Liberty Utilities to promptly inform the Commission, Staff, and parties if program costs are expected to be significantly more than estimated.	
NJ	PSE&G New Jersey	AMI	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Cloud Program includes deployment of AMI throughout PSE&G's service territory (2.2 million meters), with $721 million in investment and $73 million in operations and maintenance over five years. In total, the program will include 70 applications for the AMI, including 22 in the initial phase of the program the utility is currently seeking approval for. These applications, or use cases, include enhanced customer engagement and communications; a rate analyzer and comparator; usage and bill alerts, savings tips, and interactive bill presentment; interactive energy demand and bill management; customer segmentation and behavioral analysis; customer power quality; customer energy efficiency	PSE&G Regulatory Filings (Docket No. EO18101115)

		programs; customer service and call center performance; customer DER assistance and power quality management; customer device safety; sensor, network, and data operations; automated move-in/move-out; remote disconnect/reconnect; next generation meter-to-cash; network connectivity analysis; outage detection and analysis; outage response notification; voltage monitoring and analysis; asset load/phase management, balancing and power analysis; load profiling and forecasting; distribution losses; and revenue protection and assurance. PSE&G estimates that the program will provide $937 million in net benefits. PSE&G currently has AMR meters installed, and notes that 700,000 of its meters need to soon be replaced. PSE&G proposed semi-annual base rate adjustments to recover costs associated with the Energy Cloud Program. PSE&G is also seeking to defer as a regulatory asset the stranded costs of traditional meters not fully depreciated (about $219 million).	
PSE&G New Jersey	Energy Storage	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Electric Vehicle and Energy Storage Program includes deployment of 35 MW of energy storage, with $109 million in investment over six years and $70 in ongoing expenses over the 15-year life of the systems. Within the program, 10 MW will be used for solar smoothing (5 installations for $13.1 million), 13 MW will be used for distribution deferral (7 installations for $38.6 million), 6 MW will be used for outage management (6 installations for $20 million), 2 MW will be used for microgrids for critical facilities (1-4 installations for $25.7 million, including 4 MW of solar), and 4 MW for peak reduction for public sector facilities (4 installations for $11.9 million). PSE&G proposed a decoupling mechanism in its current general rate case, and noted in the	PSE&G Regulatory Filings (Docket No. EO18101111)

		Clean Energy Future filing that if the decoupling mechanism is not approved, the utility would be open to considering another form of decoupling or an annual lost revenue adjustment mechanism to address lost revenues due to the energy storage program. PSE&G proposed a new rider (Technology Innovation Charge) to recover the net revenue requirements associated with the energy storage and electric vehicle programs. The Technology Innovation Charge would be a per-kWh charge applied equally to all rate schedules. PSE&G filed supplemental testimony in January 2019.	
N/A	Microgrid	S.B. 713, introduced in January 2018, requires the Board of Public Utilities to establish a microgrid program for state agencies and local governments to equip critical facilities.	S.B. 713 (I)
Atlantic City Electric	Smart Grid	In February 2018, Atlantic City Electric filed a request for approval of a $338.2 million infrastructure investment program over 2019-2022 to support and enhance distribution system reliability, resiliency, and safety. The proposed investments fall into five categories: targeted reliability improvement ($66.3 million), distribution automation/telecom ($93.1 million), infrastructure renewal ($103.2 million), emergency ($46.2 million), and facilities ($29.3 million). The distribution automation category includes grid modernizing investments, including automatic sectionalizing and restoration schemes and telecommunications investments to support distribution automation. The utility also proposed a new rider as a cost recovery mechanism for the investments. Public comments hearings were held in July 2018. Atlantic City Electric filed a general rate case in August 2018, which includes requests for cost recovery for some of the infrastructure investment program costs. The utility noted that to the extent any investments are granted in either case, they will be removed from the other.	ACE Infrastructure Investment Program Proposal (Docket No. EO18020196) ACE Rate Case Application (Docket No. ER18080925)
Jersey Central Power & Light	Smart Grid	In July 2018, Jersey Central Power & Light (JCP&L) filed a four-year infrastructure plan called *JCP&L Reliability Plus* with the Board of Public Utilities. The	JCP&L Application (Docket No. EO18070728)

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		proposal includes investments in four categories: overhead circuit reliability and resiliency ($132.9 million), substation reliability enhancement ($85.9 million), distribution automation (108.4 million), and underground system improvements ($59.7 million). The total budget for the proposal is $386.8 million over four years. Projects in the overhead circuit reliability and resiliency category include lateral fuse replacement, enhanced vegetation management, back-up generator installation. Projects in the substation reliability enhancement category include flood mitigation, substation equipment replacement, mobile substations, replacement of relays with new technology, and substation fencing enhancement. Projects in the distribution automation category include circuit protection and sectionalization, installation of SCADA-line devices, construction of loop schemes with reclosers and SCADA control, implementation of an advanced distribution management system, and installation of load voltage and data monitoring points with remote terminal unit upgrades. Projects in the underground system improvements category include underground cable replacement, submersible transformer replacement, and conventional and network rehabilitation. JCP&L proposed a new cost recovery mechanism for these investments, Rider RP - JCP&L Reliability Plus Charge.	
PSE&G New Jersey	Smart Grid	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Efficiency Program includes a variety of customer-focused programs, including a Volt VAR Pilot Program, which will test smart grid technologies to control circuit voltage and reactive power on the distribution grid in order to reduce energy consumption, peak demand, and system losses, as well as to enable more solar deployment. PSE&G plans to hire a third-party contractor to	PSE&G Regulatory Filings (Docket No. EO18101113)

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			install the hardware and software upgrades. The proposed budget for the Volt VAR Pilot Program is about $16.3 million. PSE&G proposed recovering the costs of its Clean Energy Future - Energy Efficiency Program through a new component of the Green Program Recovery Charge.	
NV	NV Energy	Energy Storage	In December 2018, the Public Utilities Commission of Nevada approved NV Energy's 2019 – 2038 integrated resource plan and 2019 – 2021 energy supply plan, which includes a planned deployment of 100 MW of battery storage by 2021.	Docket No. 18-06003 Press Release
NY	PSEG Long Island	AMI	In June 2018, PSEG Long Island filed an annual update of its 2014 Utility 2.0 Long Range Plan. The update lays out plans for full AMI deployment in PSEG's service territory to take place from 2019-2022. Several parties filed comments on the plan during Q3 2018; only the New York Power Authority (NYPA) specifically addressed the AMI deployment, which it generally supported. NYPA also encouraged PSEG to prioritize public customers (and larger customers in general) for AMI deployment.	Case No. 14-01299
OH	Dayton Power & Light	AMI, Energy Storage, Microgrid, Smart Grid	In December 2018, Dayton Power & Light (DP&L) filed its $866.9 million Distribution Infrastructure Modernization Plan. The plan includes AMI deployment; investments in advanced distribution infrastructure, communications equipment, and associated equipment; implementation of an online customer portal; and investments in physical and cyber security. Specifically, the utility plans to deploy automatic reclosers, smart switches, capacitor banks with controls, air break switch controls, single phase sensors to enable distribution automation and digital relays and communication gateways to enable substation automation. The utility is also planning to invest in an advanced distribution management system (ADMS) and will create a portal through which third parties can access information collected by the ADMS. DP&L also plan to invest in conservation voltage reduction, volt/var optimization, a GIS system, a mobile workforce management system, and	Docket No. 18-1875-EL-GRD

		telecommunications infrastructure. The plan also includes development of an Analytics Center of Excellence to analyze data from various devices and systems and a Computer Information System to enable new rate structures. DP&L also plans to install 50 electric vehicle charging stations and develop a community solar demonstration project, a battery storage demonstration project, and a microgrid program. DP&L plans to test four battery storage applications: strengthening reliability, peak shaving, peak shaving with provision of residential reliability benefits, and utility-scale deployment to reduce generation purchases. DP&L plans to offer an opt-in TOU rate option once the required information systems have been installed. DP&L is proposing to recover costs associated with the plan through its existing SmartGrid Rider with quarterly true-ups. Several parties filed to be interveners in the proceeding.	
Ohio Edison d/b/a First Energy	AMI, Smart Grid	In December 2017, First Energy filed a plan outlining a three-year $450 million investment in the modernization of its distribution network. The proposed projects include circuit ties, reconductoring, reclosers, and data acquisition systems. The utilities, Commission staff, and other parties filed a stipulation in November 2018 agreeing to an aggregate of $516 million in capital investment, including AMI, an advanced distribution management system, distribution automation, and integrated volt/volt-ampere reactive control. The stipulation also establishes a Grid Mod Collaborative Group to update stakeholders and receive customer input. Stakeholders and the utility would begin discussing the development of a Grid Mod II plan by June 2020. The Attorney Examiner established a procedural schedule in November 2018 to consider the stipulation, with an evidentiary hearing commencing on February 4, 2019.	Docket No. 17-2436-EL-UNC Stipulation
Duke Energy Ohio	Energy Storage	Duke Energy Ohio filed its Electric Security Plan in June 2017. Part of its plan includes a proposal for a 10 MW pilot distribution battery storage system to be located in its southwest Ohio service territory. Duke also requested approval for	Docket No. 17-1263-EL-SSO

		a new rider mechanism to recover costs associated with PowerForward grid modernization efforts. Duke Energy filed a stipulation with a number of parties in April 2018 which recommends approval of the Electric Security Plan. In December 2018, the Commission merged several rate proceedings relevant to Duke Energy into a single docket. The Commission in its order allowed the battery storage project to go move forward as a pilot project. Duke Energy is required to file its application detailing the battery storage project in a separate proceeding. The order also approved the proposed tariffs, and Duke Energy will be filing the final tariffs for approval. In January 2019, the Ohio Consumer Counsel filed application for rehearing.	
Ohio Edison d/b/a First Energy	Smart Grid	In October 2016, the Public Utilities Commission of Ohio (PUCO) ordered First Energy to file a Distribution Modernization Rider (DMR), which would collect $600 million over three years to fund modernization of the distribution grid. First Energy filed its tariff in November 2016, and in December the Public Staff recommended its approval. The Ohio Consumers' Counsel (OCC) and the Ohio Manufacturers' Association Energy Group (OMAEG) then filed a joint motion to reject the DMR tariff. PUCO denied the consumer groups' motion and approved the DMR tariff in December 2016. The OCC filed an additional application for rehearing in January 2017, which PUCO denied in February 2017. PUCO issued its Eighth Entry for Rehearing in August 2017, which directs staff to work with a consultant to review how FirstEnergy uses the money collected under the DMR tariff. FirstEnergy filed an application for rehearing, arguing that the additional review is not necessary. In an October 2017 order, PUCO denied FirstEnergy's application for rehearing. In November 2017, the OCC filed an appeal with the Ohio Supreme Court to overturn the PUCO order granting approval for the DMR. Parties filed merit briefs with the Ohio Supreme Court during Q1 2018 and reply briefs during Q2 2018. Oral arguments took place in January 2019.	Docket No. 14-1297-EL-SSO Supreme Court No. 17-1664

OK	Public Service Company of Oklahoma	Smart Grid	In September 2018, as part of a general rate case, Public Service Company of Oklahoma proposed several smart grid investments in the areas of system automation, comprehensive system monitoring and analytics, power quality and reliability monitoring, and grid security. The investments in smart grid technologies would total $35 million annually over five years. Parties filed their lists of major issues for the proceeding on January 2, 2019.	Docket No. PUD 201800097 Press Release
PA	Duquesne Light Company	Energy Storage, Microgrid	As part of Duquesne Light Company's most recent general rate case, filed in April 2018, the utility proposed the development of a microgrid at its Woods Run campus - one of the utility's most important operations facilities - to boost electrical resilience. The proposed microgrid would include two natural gas-fueled reciprocating internal combustion engines, two battery storage banks, and three small vertical-axis wind turbines. The project budget is $9.3 million. A settlement agreement was filed in September 2018, which withdraws the proposed microgrid project. In December 2018, the Public Utility Commission approved the settlement agreement, which includes the provision that Duquesne will withdraw its Woods Run Microgrid proposal without prejudice.	Docket No. R-2018-3000124 Settlement Agreement
	N/A	Energy Storage, Microgrid	H.B. 1412 establishes a pilot program for microgrids and energy storage projects with the goal of facilitating the use of a diverse electric supply and enhancing electric distribution, resiliency, and operational flexibility.	H.B. 1412 (I)
RI	Narragansett Electric Company d/b/a National Grid	Energy Storage, Smart Grid	In December 2018, National Grid filed its Electric Infrastructure, Safety, and Reliability (ISR) plan for fiscal year 2020. The plan includes categories for spending on electric infrastructure, operation and maintenance, vegetation management, inspection and maintenance, and volt/var optimization and conservation voltage reduction (VVO/CVR) expansion. The bill impact from proposed project will result in monthly bill increase of $0.79 for a customer using 500kWh a month. The plan also includes an energy storage proposal for 250 kW / 2 hour behind-the-	Docket No. 4915

			meter energy storage to support electric vehicle charging to be completed by the end of 2019, and 500 kW /3-hour front-of-the-meter energy storage for grid support to be completed by end of 2020.	
SC	Duke Energy	AMI, Energy Storage, Smart Grid	In Duke Energy Progress' and Duke Energy Carolinas' general rate cases, filed in November 2018, the utilities requested approval for its Grid Improvement Plan. The plan is broken into three categories: (1) compliance-driven programs to protect the grid, (2) programs using advanced technologies to modernize the grid, and (3) projects and programs to optimize the customer's experience. The plan includes investments in integrated volt/var control, a self-optimizing grid (advanced distribution management system, circuit segmentation and automation, upgrading circuits and tying them together, and upgrading substations), power electronics for volt/var, distribution system automation (replace hydraulic reclosers with electronic reclosers, system intelligence and monitoring pre-scale effort, replace fuses with electronic reclosers, and underground system automation), transmission system intelligence (system intelligence and monitoring, replace electrochemical and solid state relays with digital relays, enable remote substation monitoring, and replace non-communicating switches with SCADA and remote control enabled switches), AMI, and energy storage (storage control system). The plan also includes distribution transformer retrofits, transmission bank replacement, oil breaker replacement, transmission hardening, flood hardening, targeted undergrounding, and reliability investments (hardening, circuit relocations, new circuit ties, undergrounding, energy storage) at individual sites with high potential for long duration outages with high impact. The plan also includes developing an Integrated System Operations Planning (ISOP) process that will integrate generation, transmission, distribution, and customer program planning, as well as a data access program that will integrate customer data with Green Button. The plan also includes physical security and cybersecurity investments, including	Docket No. 2018-318-E Docket No. 2018-319-E SC Grid Improvement Plan Budget Grid Improvement Plan

			fencing, lighting, intrusion detection technology, replacing Windows-based relays with devices to operate in a Linux environment, firewalls, replacement of vulnerable devices, and EMP protection. The plan also includes electric transportation programs that have been proposed by the utility in a separate proceeding. The three-year total budget for the plan is about $455 million for the two utilities.	
VA	Appalachian Power Co.	AMI, Smart Grid	In December 2018, Appalachian Power filed for approval of a plan for electric distribution grid transformation projects as part of the 2018 Grid Transformation and Security Act (S.B. 966). The plan includes a proposal to incorporate Appalachian Power's existing program of replacing distribution assets that are at the end of their useful lives with infrastructure that facilitates the integration of DERs or enhances the reliability and security of the grid. The plan includes continued replacement of Automated Meter Reading (AMR) equipment, with a goal of replacing all of the meters in its service territory by the end of 2022. Other plans include asset improvement projects, a grid automation project, vegetation management, and distribution grid security and cyber security projects.	Docket No. PUR-2018-00198
	Dominion Virginia Power	AMI, Smart Grid	Dominion filed a Petition for approval of Phase 1 of its Grid Transformation Plan. Phase 1 covers the first three years of the ten-year plan, and has an estimated cost of $816.3 million with an additional $101.5 million in operations and maintenance costs. The entire 10-year plan has a cost of $5.98 billion. The plan includes full deployment of smart meters throughout its service territory, reaching 1.4 million smart meters during Phase I (2019-2021) with an additional 600,000 installed during 2022-2023. The plan also includes the deployment of smart grid technologies, a customer information platform, grid resiliency measures, and physical and cyber security measures. The Commission is required to issue its final order on the Petition within six months of the filing date. The Commission filed an Order in July 2018 establishing the procedural schedule. Dominion filed	Docket No. PUR-18-00100

		extensive testimony in October and November 2018, and a hearing was held in November. In January 2019, the State Corporation Commission (SCC) issued a final order approving the Phase I costs for cyber and physical security ($35.2 million), and some telecommunications costs ($119.2 million) as reasonable and prudent. Over 10 years, the cyber and physical security cost would be $106.9 million and the telecommunications cost would be $803.4 million. Other costs for AMI ($523.8 million for Phase I / $824.4 million over 10 years), intelligent grid devices ($104.6 million for Phase I / $776 million over 10 years), and grid hardening ($486.1 million for Phase I / $3 billion over 10 years) were not approved. The SCC is open to Dominion re-filing more developed costs and plans for proposals that were not approved.	
Appalachian Power Co.	Energy Storage	S.B. 966, enacted in March 2018, requires Dominion Virginia Power and Appalachian Power to submit proposals to deploy up to 30 MW and 10 MW respectively of battery storage as a pilot project. The bill also directs the State Corporation Commission, by December 1, 2018, to adopt rules or guidelines as necessary for the general administration of the pilot programs. The Commission opened a new proceeding for each utility's pilot project in April 2018. The utilities filed a joint comment in June 2018, in which they argued that the Commission should establish guidelines for the general administration of the pilot programs, but not initiate a formal rulemaking at this time. The joint comment also included draft guidelines for the Commission to consider. The proposed guidelines include a description of the contents to be included in a utility's filing, including the project's location, capacity, technology, in-service date, useful life and decommissioning, asset classification, objective, and metrics and performance data. In November 2018, the Commission issued an order adopting guidelines for the pilot programs. Each utility will file its pilot program for deployment of up to 10 MW of energy storage for Appalachian Power, and 30 MW for Dominion Energy. The utilities' pilot proposals will include location, capacity, technology,	Docket No. PUR-2018-00059 S.B. 966 (E)

			decommissioning, cost, asset classification (generation, transmission, or distribution asset), objective of the proposal (either to improve reliability, improve integration of DERs, defer investment, reduce peak demand, or to be customer-sited). Utility proposals are due by March 31, 2019.	
	Dominion Virginia Power	Energy Storage	S.B. 966, enacted in March 2018, requires Dominion Virginia Power and Appalachian Power to submit proposals to deploy up to 30 MW and 10 MW respectively of battery storage as a pilot project. The bill also directs the State Corporation Commission, by December 1, 2018, to adopt rules or guidelines as necessary for the general administration of the pilot programs. The Commission opened a new proceeding for each utility's pilot project in April 2018. The utilities filed a joint comment in June 2018, in which they argued that the Commission should establish guidelines for the general administration of the pilot programs, but not initiate a formal rulemaking at this time. The joint comment also included draft guidelines for the Commission to consider. The proposed guidelines include a description of the contents to be included in a utility's filing, including the project's location, capacity, technology, in-service date, useful life and decommissioning, asset classification, objective, and metrics and performance data. In November 2018, the Commission issued an order adopting guidelines for the pilot programs. Each utility will file its pilot program for deployment of up to 10 MW of energy storage for Appalachian Power, and 30 MW for Dominion Energy. The utilities' pilot proposals will include location, capacity, technology, decommissioning, cost, asset classification (generation, transmission, or distribution asset), objective of the proposal (either to improve reliability, improve integration of DERs, defer investment, reduce peak demand, or to be customer-sited). Utility proposals are due by March 31, 2019.	S.B. 966 (E) Docket No. PUR-2018-00060
VT	Green Mountain Power	Energy Storage, Microgrid	In November 2017, Green Mountain Power filed a request for a Certificate of Public Good for its proposed MicroGrid-Milton Project. The proposed project is a	Docket No. 17-5003-PET

		microgrid, including a 4.99 MW solar facility and a 2 MW battery storage facility (2 MW/8 MWh Tesla Powerpack.) The estimated cost of the project is $13.4 million. A hearing was held in mid-October 2018.	
Green Mountain Power	Energy Storage, Microgrid	In December 2017, Green Mountain Power filed a request for a Certificate of Public Good for its proposed MicroGrid-Ferrisburgh Project. The proposed project is a microgrid, including a 4.99 solar facility and a 2 MW battery storage facility (2 MW/8 MWh Tesla Powerpack.) The estimated cost of the project is $13.5 million. Later in December, the Public Utility Commission issued an order, finding the application incomplete. Green Mountain Power refiled its petition in March 2018, which the Commission found complete. An evidentiary hearing is scheduled for November 2nd.	Docket No. 17-5236-PET

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of late January 2019.

Q1 2019 OUTLOOK

Most state legislatures are beginning their 2019 sessions in the first quarter of the year. Several bills relating to energy storage, microgrids, advanced metering infrastructure, and distribution system planning have already been introduced in 2019.

Lawmakers in **Connecticut**, **Minnesota**, **New Hampshire**, and **New Mexico** introduced bills initiating energy storage or microgrid studies in January 2019. Another bill in **New Mexico** would authorize decoupling, and a **Hawaii** bill would establish an energy storage tax credit.

Multiple bills related to grid resilience were introduced in **Hawaii**, while bills related to data access and distribution system planning were introduced in **Virginia** and **Washington**, respectively. Bills related to AMI and cybersecurity were introduced in **Texas**.

Hawaii's study on utility business models is scheduled to be released in Q1 2019, as is **Illinois**' final NextGrid report. The **New Hampshire** Public Utilities Commission will consider the proposed scope for a distribution-level locational value study, and a final order in **Connecticut**'s grid modernization investigation is expected during Q1 2019.

Tampa Electric in **Florida** requested approval for an AMI opt-out tariff in January 2019, including a one-time fee of $96.27 and a monthly fee of $20.64. Avista Utilities in **Washington** also requested modifications to its opt-out tariff to specify that net metering customers cannot opt out of AMI installation.

In January 2019, the **New Hampshire** Public Utilities Commission issued an order approving a modified version of Liberty Utilities' proposed behind-the-meter energy storage program. In **Vermont**, Green Mountain Power and Efficiency Vermont filed a data access standard.

The **Massachusetts** Department of Public Utilities (DPU) issued an order authorizing solar-plus-storage net metering under certain configurations in early February 2019. The DPU also approved a new performance-based incentive for energy storage as part of the state's three-year energy efficiency plan.

The **Virginia** Corporation Commission issued an order on Dominion's grid modernization plan, significantly scaling back the proposed investments. In **Nevada**, NV Energy issued an RFP for 400 to 600 MW of non-technology specific resources for summer peak planning capacity.

Tucson Electric Power and UNS Electric in **Arizona** filed their R-TECH rates in January 2019. Rate cases are expected to be filed by several utilities in Q1 2019, including SWEPCO in **Arkansas**, Interstate Power & Light in **Iowa**, Emera in **Maine**, Consolidated Edison in **New York**, and Xcel Energy in **Wisconsin**.

ENDNOTES

[1] Energy Storage Association, *Facts and Figures*, 2018, http://energystorage.org/energy-storage/facts-figures

[2] Adam Cooper, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid*, The Edison Foundation Institute for Electric Innovation, December 2017, http://www.edisonfoundation.net/iei/publications/Documents/IEI_Smart%20Meter%20Report%202017_FINAL.pdf